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New York, NY 10011

David F. Garcia, P.E.
United States Environmental Protection Agency, Region 6
Director
Air & Radiation Division
1201 Elm Street, Suite 500
Dallas, Texas 75270

Dear Mr. Garcia,

RE: NFE Response to Incomplete Application Determination – Clean Air Act New Source Review and Title V Permit Application New Fortress Energy Louisiana FLNG Deepwater Port Project

New Fortress Energy ("NFE") respectfully submits the enclosed documentation in response to the United States Environmental Protection Agency's ("USEPA's") Incomplete Application Determination letter dated December 19, 2022 for the Clean Air Act New Source Review and Title V Permit Application for the New Fortress Energy Louisiana FLNG Deepwater Port Project.

A response to each request in the USEPA's letter is provided below.

General (Title V):

1. *Include the EPA Part 71 permitting forms (See EPA Instruction Manual for Part 71 Forms) - General Information and Summary (GIS), Certification of Truth, Accuracy and Completeness (CTAC) (40 CFR §§ 71.5(a)(2) and 71.5(d)), and Initial Compliance Plan and Compliance Certification (Form I-Comp). The submittal of the I-Comp form is required in a title V permit application in accordance with 40 CFR 71.5(c)(8). The information in this form also supports the title V permit application requirements found at 40 CFR 71.5(c)(3)(v)-(vii) and (4)-(5).*

   Attachment A includes the following completed USEPA Part 71 permitting forms: General Information and Summary (GIS); Certification of Truth, Accuracy and Completeness (CTAC); and Initial Compliance Plan and Compliance Certification (Form I-Comp).

2. *The LDEQ Application for Approval of Emissions of Air Pollutants from Part 70 Sources form should be completed in its entirety. LDEQ Regulatory Review Analysis Tables (Section 22) are incomplete as they do not appear to address all potentially applicable requirements. EPA requests that New Fortress Energy (NFE) address discrepancies and/or clarify applicability of the following items. [LAC 33:III.517.D].*

   a. *Under Section 22 of the Part 70 Sources form, negative applicability determinations made elsewhere in the application (e.g., LAC 33:III Sections 2103, 2107, 2108, and NSPS Dc, Kb, OOOO, OOOOa, and NESHAP YYYY, ZZZZ, DDDDD, H, Y, HH, HHH, SS) should be reflected on Table 1.*

      Attachment B includes an updated Section 22 of the Part 70 Sources form including an updated Table 1 with a complete list of negative applicability determinations.

   b. *Under Section 22 of the Part 70 Sources form, negative applicability determinations for LAC 33:III Chapter 51/59 and Section 2103, 2107, 2108 and NSPS/NESHAP SS, ZZZZ, DDDDD, Dc should be reflected on Table 3.*

Attachment B includes an updated Section 22 of the Part 70 Sources form including an updated Table 3 with a complete list of exemptions and negative applicability determinations.

c. *Under Section 22 of the Part 70 Sources form, emission units that are applicable to various Part 60/63/98 regulations should also be identified in Table 1 (e.g., A, JJJJJJ, W). Ensure all applicable requirements added are also reflected in Table 2 for each associated unit*.

Attachment B includes an updated Section 22 of the Part 70 Sources form including updated Tables 1 and 2 identifying all applicable requirements.

d. *Page 3-10 of the application suggests that LAC 33:III Chapter 15 applies to various units. However, in Section 22 of the Part 70 Sources form, Chapter 15 is not listed on Table 1 for the relevant emission units. Table 1 should address all potentially applicable regulations and Table 2 should reflect the compliance method provisions for these missing units*.

Attachment B includes an updated Section 22 of the Part 70 Sources form including updated Tables 1 and 2 identifying all applicable requirements.

e. *Page 3-10 of the application suggests that LAC 33:III Chapter 13 applies to the FSU boilers. However, Table 3 does not list the explanation of the non-applicability of LAC 33.III Chapter 13 (e.g., LAC 33.III 1311.C / 1313.C) to other proposed units. Table 3 should include an explanation of the negative applicability finding for Chapter 13 to flares, thermal oxidizers, and combustion turbines. If LAC 33.III Chapter 13 is applicable to these units (and any other unit identified in Table 1), Table 2 should identify all of the applicable requirements and compliance method provisions*.

Attachment B includes an updated Section 22 of the Part 70 Sources form including updated Tables 2 and 3 identifying all applicable requirements and compliance method provisions.

f. *Ensure Section 22 Table 2 (State and Federal Air Quality Requirements) includes all relevant applicable requirements for each associated emissions unit and facility-wide requirements. For example, for all 11 turbines the only applicable requirement addressed is NSPS KKKK – the application should include any other applicable LAC 33:III requirements (e.g., Chapter 13 and 15). For both thermal oxidizers, the only applicable requirement listed in Table 2 is Chapter 11 – the application should include any other applicable LAC 33:III requirements e.g., Chapter 13 and 15. In addition, the facility-wide requirements exclude several previously identified applicable requirements (e.g., LAC 33:III Chapter 11, 15, etc).*

Attachment B includes an updated Section 22 of the Part 70 Sources form including an updated Table 2 identifying all applicable requirements.

g. *For each regulation that provides a compliance method option, ensure that Table 2 identifies the specific method of compliance that will be employed. For example, for all 11 combustion turbines, Table 2 cites 40 CFR 60.4340(a) regarding annual performance testing. However, the compliance method/provision column also includes alternative monitoring per 40 CFR 60.4340(b)(1)-(2). Please specify which of these compliance methods NFE intends to utilize to ensure other potentially applicable recordkeeping requirements are accounted for (i.e., if NFE is proposing to use utilize CEMs or CPMS, such recordkeeping requirements should be listed in Table 2). Confirm the proposed compliance mechanism*.

NFE will demonstrate continuous compliance for the combustion turbines subject to 40 CFR 60 Subpart KKKK in accordance with 40 CFR 60.4340(b)(2)(ii) by continuously monitoring the appropriate parameters to determine whether the unit is operating in low-NO_X mode. This compliance method is noted in the revised forms provided in Attachment B.

h. *Section 22 Table 3 states that 40 CFR Part 64 does not apply because "The Project's emission sources do not employ a control device as defined in 40 CFR 64.1." citing to 40 CFR 64.2(a)(2). EPA requests additional justification for this negative applicability determination. The flares and thermal oxidizers of the gas treatment system appear to meet the definition of a control device with pre-controlled PTE greater than the major source threshold and use for achieving compliance with an emission limitation. For the record, include a description of why each potentially affected unit is exempt from CAM per 40 CFR 64.2(b)(1).*

A review of the controlled and uncontrolled volatile organic compound ("VOC") emission rates for the thermal oxidizers, dry flares, and wet flares indicate that these devices are subject to 40 CFR Part 64. Attachment C includes compliance assurance monitoring ("CAM") plans to comply with the requirements of 40 CFR 64.2(b)(1).

i. *Provide the basis for concluding that the amine storage tanks contain no VOCs. Does NFE anticipate any emissions associated with process wastewater due to entrained hydrocarbons?*

The amine used for the Project will be methyl diethanolamine, which is a VOC. The application incorrectly noted that amine storage would not contain any VOCs as related to the applicability to New Source Performance Standard ("NSPS") Subpart Kb. However, methyl diethanolamine has a vapor pressure less than 0.011 kPA and is therefore exempt from NSPS Subpart Kb.

No measurable hydrocarbon emissions are expected from the process wastewater.

j. *The permit application identifies 62 non-insignificant fuel oil tanks associated with FLNG1, FLNG2, and the FSU. EPA requests an Emissions Inventory Questionnaire (EIQ) form for <u>each</u> emissions unit (including each tank) and for the relevant regulatory applicability tables be completed. Please confirm that NFE is requesting to establish an emissions cap for these 62 tanks and that they exclusively store No. 2 fuel oil. In addition, negative applicability for relevant LAC 33:III requirements should be included in Table 3. Emission calculations for these tanks should also include maximum lb/hr emission rates based on maximum vapor pressure.*

On the revised application forms in Attachment B, NFE requests that these storage tanks be exempt in accordance with LAC 33:III 501(B)5 with combined potential VOC emissions less than 5 tpy. Therefore, no emission limits are proposed for these tanks.

3. *FSU Wartsila Engines – Provide a detailed description of how the Wartsila dual fuel engines (12V50DF and 6L50DF) on board the FSU are utilized during normal operations or in support of the industrial process during LNG production and loading of LNG carriers. Will these engines be used to assist in the transfer of LNG from the FSU to LNG carriers calling on the port? [71.5(c)(5), LAC 33:III.517.D].*

The Wartsila Model 12V50DF and 6L50DF dual fuel engines will not be used during normal operations or in support of the industrial process during LNG production and loading of LNG carriers.

4. *In accordance with 40 CFR 52.21(n)(1)(i) and LAC 33:III.509.N, EPA requests a detailed equipment layout schematic for each of the 6 platforms. The diagrams should clearly identify each emission unit (including the location of any tanks and insignificant or existing emission sources). Please ensure the emission point IDs on these diagrams can be correlated to the emission units proposed in the application. In addition, provide a process flow diagram which also identifies all associated EPNs*.

   Attachment D provides equipment layout drawings for FLNG1, FLNG2, and the FSU showing the location of each significant emission source that will be covered by the PSD permit. Including the insignificant emission sources, such as the oil storage tanks, would unnecessarily clutter the figures and make identification of the significant sources less transparent. Therefore, the figures provided in Attachment D do not include the insignificant emission sources.

5. *Include a detailed process description of the project's entire process from feed gas metering and conditioning to final LNG storage and loading. Please include intermediate steps that could have potential to generate emissions (i.e., heavy hydrocarbon removal / condensate generation). Describe how heavy compounds are removed from feed gas and how condensate will be handled. [52.21(b), LAC 33:III.517.D.2]*.

   Provided in Attachment E is a detailed process description for FLNG1 and FLNG2. There is no dedicated material handling equipment for condensate, as condensate is not a product for the Project. Condensate is fed into the fuel gas for the power generation combustion turbines.

6. *To assist in the understanding and verification of the basis for emission rate calculations, in addition to the PDF version of emission calculations, please provide accessible electronic versions of the emission calculations for all emission units (i.e., unlocked Excel spreadsheets containing the underlying formulas used to calculate the lb/hr and TPY table inputs). [LAC 33:III.517.D.9] Please be aware that EPA considers that "… even emission factors with more highly rated AP-42 Grades of 'A' or 'B' are only based on averages of data from multiple, albeit similar, sources… Accordingly, these factors are not likely to be accurate predictors of emissions from any one specific source, except in very limited scenarios." See EPA Publication no. EPA 325-N-20-001 (November, 2020). Therefore, when relying on AP-42, any additional data or information specific to your project design and operations should be considered and presented to support your use of such factors in the permit applications*.

   NFE is submitting an electronic copy of the emission calculations in Microsoft Excel format, concurrent with the submittal of this response to the EPA.

   EPA Publication No. EPA 325-N-20-001 (November 2020) discusses the impact of incorrect emissions with regards to compliance with short-term National Ambient Air Quality Standards (NAAQS) or for under reporting for emission fees. AP-42 emission factors have been applied for pollutants and emission sources without available vendor emission specifications. AP-42 emission factors have been used for Hazardous Air Pollutants ("HAPs") but there are no NAAQS which would be impacted by using these emission factors and fees are not paid for HAP emissions. NFE believes that the use of other AP-42 emission factors in the application are sufficiently conservative, such as particulate matter emissions from the thermal oxidizers and flares, or for small emission sources such as the FSU boilers, such that the use of these factors are not under reporting emissions. Therefore, the use of AP_42 emission factors in the application would not materially impact NAAQS compliance or emissions fees. NFE believes that application of AP-42 emission factors in the application is consistent with industry practice for similar sources and pollutants for which they were applied. On this basis, the use of AP-42 emission factors in the application will not impact NAAQS compliance or emissions fees and therefore, are in accordance with EPA guidance.

7. *The application identifies several tanks claimed as insignificant per LAC 33:III.501.B.5.A.3. For the permit record, provide tank emission calculations for these units to demonstrate their insignificance. [LAC 33:III.501.B.5].*

   Potential emissions have been calculated for all storage tanks and are provided in the updated emission calculations included in Attachment F.

8. *Include a complete Section 24.C of the LA Part 70 application (or a similar table) summarizing proposed BACT (i.e., technology, limit, and averaging period) for each pollutant and type of unit proposed (Compression / Power Turbines, Flares, TO, Fugitives, etc).*

   Attachment B includes an updated Section 24.C of the Part 70 Sources form summarizing proposed BACT for each PSD subject pollutant and emission unit.

9. *Are all emission units considered new? Does NFE consider any units as reconstructed or modified units? Please identify any existing equipment or emission sources that will be utilized along with any equipment information (manufacturer, make/model, install or modification dates).*

   The emergency generator engines on FLNG1 are all existing engines and were manufactured prior to June 2006. Accordingly, these emergency engines are not subject to New Source Performance Standard (NSPS) Subpart IIII but are subject to National Emission Standards for Hazardous Pollutants (NESHAP) Subpart ZZZZ. The emission rates utilized to estimate potential emissions from these engines were the potential site variation emission rates provided by Caterpillar and therefore there is no change in emissions. The revised LA Part 70 application forms and new EPA Part 71 application forms include this change. The Project's remaining emission units are all new sources.

Best Available Control Technology (BACT): [52.21(n)(1)(iii) / LAC 33:III.509.N.1.c]

1. *Where "good combustion practices" are proposed as an element of BACT, provide details of what this means specifically to ensure that such requirements can be incorporated as practically enforceable limits in the permit.*

   For each emission unit that identifies good combustion practices as an element of BACT, NFE proposes to operate and maintain the emission unit in accordance with vendor recommendations. NFE shall develop an operating and maintenance ("O&M") plan for each unit that details a schedule for completing periodic preventative maintenance checks and tune-ups for each emission unit to ensure good combustion. The O&M plan will be in place prior to the commencement of operation and will be provided upon request.

2. *Combustion Turbine BACT Analysis (General): The control technology review evaluates all combustion turbines together, stating "The BACT analysis for the compression and power generating turbines is combined as these emission units are all simple cycle combustion turbines fired solely with natural gas or BOG, which will have comparable characteristics as natural gas." As a result, the application does not contain a separate top-down BACT analysis for each type of combustion turbine proposed for the project. Because the turbines operate with different purposes (mechanical drive refrigeration & feed gas compression vs. power generation), are of different size, model, and capacities (aeroderivative vs. heavy frame), are proposed with different BACT emission rates, and due to the case-by-case nature of BACT, NFE needs to provide a complete BACT analysis for each type of turbine separately in accordance with EPA's top-down BACT*

procedure and 40 CFR § 52.21(j). This analysis should articulate the technical feasibility of potential control technologies for each turbine type (compression vs. power generation). For example, currently, the application has not attempted to distinguish the feasibility of SCR or the variability in achievable NOx BACT emission rates on mechanical drive aeroderivative/heavy frame industrial turbines in compression service from frame-type turbines in power generating service (with and without waste heat recovery).

Attachment F includes a revised BACT analysis that evaluates each combustion turbine model separately. The feasibility of SCR on the combustion turbines is addressed in response to items 3 through 7 below.

3. *<u>Combustion Turbine BACT Analysis (NOx):</u> As a part of the control technology review for combustion turbines, under BACT Step 2, NFE eliminates SCR emission control technology for all combustion turbines (in both compression service and power generation service) due to technical infeasibility. The justification provided for technical infeasibility under Step 2 for all turbine types is based on the following considerations: 1) Additional housing requirements to accommodate the catalyst and ammonia injection grid as well as ammonia storage tanks; 2) Additional ductwork required to inject ambient air to lower exhaust temperature within the proper operating temperature of the SCR catalyst; and 3) There are no known offshore LNG export facilities utilizing SCR on combustion turbines. Ultimately, the application states at Step 2 that the SCR housing and tempering air systems would require vertical installation above existing equipment due to very limited deck space on the platforms and as a result, is economically prohibitive. EPA notes that a demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review. See U.S. EPA, New Source Review Workshop Manual (Draft, 1990) at B.7. The technical feasibility of a control technology and/or alternative is generally based on whether the control has been installed or operated successfully on the type of emission unit under review (i.e., demonstrated in practice). If demonstrated in practice, the technology is considered technically feasible. For undemonstrated control technologies, technical feasibility is determined by an evaluation of whether the technology is both "available" and "applicable" (i.e., commercially-available with no physical or chemical characteristics of the emissions stream that prevent application of the technology and can reasonably be deployed on the source type under consideration). With regard to "applicability", if a commercially available control technology has been deployed or is soon to be deployed (e.g., is specified in an issued permit) for the same or similar source type, the control technology is presumed applicable. Therefore, EPA requests additional supporting justification on the following items.*

   a. *<u>Technology not demonstrated offshore:</u> The location of the proposed liquefaction trains and associated emission units on an offshore platform does not appear to be relevant in determining whether SCR control technology is demonstrated in practice and thus technically feasible for the combustion turbines under review. As supported by numerous RBLC entries, the operation of combustion turbines with SCR is considered demonstrated in practice or available and applicable for the purposes of determining technical feasibility of the technology. EPA notes that under Step 1 of the BACT analysis, the permit application at 4-5 acknowledges that SCR is a control technology "... that has been successfully demonstrated on simple-cycle turbines." However, if it is NFE's position that SCR is an undemonstrated technology for the source type (both refrigeration compression and power-generating turbines) and wishes to propose this as justification for technical infeasibility of the control technology, NFE should also provide sufficient justification for each type of turbine to demonstrate that the technology is not also both "available" and "applicable" as defined in EPA guidance. Specifically, NFE needs to provide justification for how SCR control systems are not commercially available and cannot be reasonably installed and operated on the offshore platforms. Such justification should include a discussion of how operating SCR on a platform is an unresolvable technical difficulty and how the physical and chemical* *characteristics of the pollutant-bearing gas stream for onshore combustion turbines at liquefaction facilities are materially different from those proposed offshore. Additionally, as outlined in the NSR Workshop Manual at B.18, in general, a commercially available control option will be presumed applicable if it has been or is soon to be deployed (e.g., is specified in a permit) on the same or a similar source type. A few examples of recently permitted LNG liquefaction sources from the RBLC include: 1) 2018 Driftwood LNG (LA) permit authorizing DLN and/or SCR on refrigeration compression combustion turbines (simple cycle aero-derivative & IPSMR); 2) 2020 Lake Charles LNG (LA) permit proposing to utilize SCR/DLN and Catalytic Oxidation controls on refrigeration compression combustion turbines (aero-derivative & simple cycle); and 3) 2016 permit issued Golden Pass LNG (LA) proposing to utilize SCR/DLN and Catalytic Oxidation controls on a frame-type GE 7EA turbine (with HRSGs).*

If NFE does in fact believe SCR is a technically feasible control option and that such an option is economically prohibitive, EPA recommends that NFE continue the top-down BACT process for SCR beyond Step 2. Currently, the application conflates technical feasibility with economic feasibility.

A combustion turbine operating at a deepwater port is not functionally different than a combustion turbine operating on land, whether that combustion turbine is used to drive an electric generator or a compression train. However, the location of the combustion turbine at a deepwater port is relevant to the amount of space available to install additional equipment, including SCR. Land based combustion turbines have an unlimited amount of space to add control equipment. An SCR system requires additional duct work, ammonia storage tanks, ammonia pumps, and an enclosure for the ammonia injection grid and SCR catalyst. All of the projects cited with SCR are land-based projects and there are no known deepwater port LNG liquefaction projects that have installed SCR on combustion turbines. This highlights the relevancy of the difference between a land-based combustion turbine installation versus a deepwater port installation as SCR has not been demonstrated in practice on a deepwater port.

The FLNG1 platforms are existing structures that cannot be modified. On FLNG1, the LM6000 compressor train is mounted on the forward-facing deck of the Pioneer II platform adjacent to the forward rig leg. The LM6000 compressor train is situated close to the platform edge such that no additional space is available for mounting the SCR equipment. The additional SCR equipment cited above would also cause the platform to exceed its design weight limit. For these reasons, SCR on the FLNG1 LM6000 compressor turbine is not technically feasible. Similarly, the Siemens SGT-400 combustion turbines are co-located which limits the available space for installing SCR and could cause the platform to exceed its design weight limit. For these reasons, SCR on the FLMNG1 combustion turbines is not technically feasible.

The FLNG2 platform can accommodate can SCR on the LM6000 combustion turbine. Accordingly, NFE will install SCR on the LM6000 combustion turbine. However, the Project's design cannot accommodate SCR on the Siemens SGT-400 power generating turbines. The location of these turbines, near the platform's emergency generating and fire pump engines, cannot accommodate the additional duct work, ammonia storage tanks, ammonia pumps, and catalyst enclosure for an SCR system. There is no other location on the platform to relocate the Siemens SGT-400 turbines and therefore it was determined that SCR on the Siemens SGT-400 turbines is not technically feasible.

The Solar 70 compressor turbines have been removed from the Project's design. This change has been addressed in the materials provided with this submittal.

b. <u>*Limited platform space as justification for technical infeasibility:*</u> *EPA guidance has outlined that "Physical modifications needed to resolve technical obstacles do not in and of themselves provide a justification for eliminating the control technique on the basis of technical infeasibility. However, the cost of such modifications can be considered in estimating cost and economic impacts which, in turn, may form the basis for eliminating a control technology." See NSR Workshop Manual at B.24. Has NFE considered and evaluated the structural modification, improvement, or optimization of deck space to accommodate the installation of additional abatement equipment such as SCR? Has NFE conducted a strength and fatigue analysis of the proposed platforms to support the technical engineering justification as to why such controls and associated ductwork for an air injection system could not be installed? Please provide any further information and rationale (with supporting documentation) identifying that structural modification or space optimization of the yet-to-be-constructed platforms is not possible (i.e., an unresolvable technical difficulty) to accommodate additional abatement equipment such as SCR*.

   As discussed in response to 3a., there is insufficient space to accommodate SCR equipment for the combustion turbines on FLNG1 and SCR equipment would exceed the rated weight limit of the platforms. There is also insufficient space to accommodate SCR on the Siemens SGT-400 power generating turbines on FLNG2. The FLNG2 LM6000 compressor combustion turbine will be equipped with SCR.

c. Page 4-4 of the application states that "Combustion turbines employed in other applications, including power generation and onshore natural gas compressor stations, were deemed not representative of the Project's combustion turbines as these land-based units do not have to address variability in the natural gas fired or the space constraints of an offshore platform." Please explain in detail what variability the NFE FLNG DWP will experience in the natural gas fired and how such variability is different from what is fired in similar land-based turbines in power generating service. Also explain in detail the significant differences in the physical and chemical characteristics of the exhaust gas stream for each type of proposed offshore turbine (refrigerant compression / power generation) compared to the aforementioned land-based units that precludes the technology transfer of SCR offshore.

   There is no significant technical difference in combustion turbines for power generation and compression/refrigeration. A combustion turbine is used to drive a shaft which can be used to produce power or compression/refrigeration. The size of a combustion turbine and its design as an aeroderivative or frame unit will affect the exhaust temperature. Simple cycle combustion turbines have elevated exhaust temperatures that may preclude the use of SCR. The GE LM6000 and Solar 70 combustion turbines proposed for the NFE Project have an exhaust temperature above 900°F which is above the operating temperature window of conventional SCR. This has been accounted for in the design of the SCR that will be installed on the FLNG2 LM6000 combustion turbine through the use of tempering air injected into the turbine exhaust to lower the temperature into the operating window of the SCR.

   The Project's equipment will be designed to handle lean gas, rich gas, and design case gas. The lean gas has the highest methane content, up to 89% by weight, and the rich gas has the lowest methane content, down to 73% by weight. The design case gas has a methane content of 84% by weight. The differences in methane content affect the heat content of the gas and can affect combustion characteristics. These potential changes in the natural gas fired affect the performance emissions guarantees that are provided by the combustion turbine vendors. Additionally, natural gas condensates will be injected into the fuel gas for the SGT-400 combustion turbines which will provide additional variability in the combustion characteristics for these units. NFE has secured the lowest performance emission guarantees available from the combustion turbine vendors for the Project.

d. *The application states at 4-6 that additional ductwork would be required to cool the exhaust temperature to within proper operating temperature of the SCR catalyst for aeroderivative GE LM6000PF (refrigeration compression) and frame-type Solar Taurus 70 (feed gas compression) turbines. The application does not address the six proposed 16 MW simple cycle Siemens SGT-400 combustion turbines in power generation service that are proposed to operate with waste heat recovery. Please provide justification for why NFE believes SCR is also technically infeasible for the proposed SGT-400 combustion turbines. Are there differences in equipment size / design from power generating turbines onshore that utilize SCR? Does NFE expect a reduction in exhaust temperature due to waste heat recovery and does this affect ductwork requirements? Has NFE evaluated the use of a high-temperature zeolite based catalyst and the potential for such a catalyst to operate effectively without damage at temperature ranges expected for all proposed turbines (~900-1000F)?*

   As discussed in response to 3a., there is insufficient space to accommodate SCR equipment for the combustion turbines on FLNG1 and the FLNG2 Siemens SGT-400 combustion turbine. The LM6000 combustion turbine on FLNG2 will be equipped with SCR.

4. *<u>Proposed BACT NOx Limitation for Combustion Turbines</u>: As a part of the control technology review for combustion turbines, under BACT Step 4, the application states on page 4-7 that review of the RBLC identified that "...numerous combustion turbines at LNG production facilities utilize DLN combustors as the sole control to meet BACT. Three land-based combustion turbines equipped with SCR operating at LNG production facilities were identified but no offshore LNG export facilities were identified using SCR on combustion turbines." NFE's justification for the proposed NOx BACT limit appears to be based on the guaranteed NOx emission rate from turbine vendors and the absence of other operating offshore liquefaction facilities. The application does not explain why the onshore turbines at proposed (and permitted) LNG export facilities with notably lower NOx limits for turbines of similar size and purpose are not meaningful to the BACT analysis for NFE's DWP project. While it is not mandatory to select a specific NOx limit as BACT solely because another similar source has done so, NFE's source-specific evaluation and basis for selecting a less stringent limit should be presented in the permit application in order to be properly documented in the permit record.*

   NFE's proposed NOx BACT emission rate for the refrigeration compression turbines (aero derivative GE LM6000PF) is 25 ppmvd @ 15% O2 with DLE. The proposed NOx BACT emission rate for the Solar Taurus 70 industrial feed gas compression turbines is proposed at 15 ppmvd @ 15% O2 with DLN. The RBLC entries provided in Table C-1 of the application identified several LNG facilities with lower NOx limits in the including, but not limited to 1) Driftwood LNG permitted for a NOx limit of 5 ppmvd using aeroderivative GE LM6000PF with SCR and/or DLE; 2) Lake Charles LNG permitted for 3.1 ppmvd using aeroderivative turbines with SCR/DLE; 3) Cameron LNG permitted for a NOx limit of 15 ppmvd using GE Frame 7 turbines with DLN; and 4) Port Arthur LNG permitted for a NOx limit of 9 ppmvd using DLN on frame-type turbines. EPA's cursory review of the RBLC identified additional turbines in compressor service with lower proposed NOx limits in the 2.5 – 25 ppmvd range including, but not limited to 1) Rio Grande LNG permitted for a NOx limit of 5 ppmvd using GE Frame 7EA turbines with DLN and heat recovery, Golden Pass LNG permitted for a NOx limit of 5 ppmvd using GE Frame 7EA with SCR, and Dominion Cove Point LNG permitted for 2.5 ppmvd using GE Frame 7EA turbines with HRSG. The turbines proposed by NFE do not approach these permitted NOx BACT limits and the application does not currently justify why a less stringent limit is appropriate or why the performance levels at these sources are not comparable, technically feasible, or achievable.

NFE's permit application needs to provide detailed justification as to why the proposed LM6000PF and Solar Taurus 70 compression turbines are meaningfully different from those at permitted sources identified in the RBLC which are achieving (or have proposed to achieve via issued permits) more stringent NOx limits.[1] To ensure the application of BACT pursuant to 40 CFR 52.21(j), beyond manufacturer guarantee, please provide further justification for why the proposed limit of 25 ppmvd should be considered BACT-level of control for NOx from the GE LM6000PF turbines. Please provide further justification for why the proposed limit of 15 ppmvd is considered BACT-level of control for NOx from the industrial Solar Taurus 70 turbines

As discussed in response to 3a., there is insufficient space to accommodate SCR equipment for the combustion turbines on FLNG1 and the FLNG2 Siemens SGT-400 combustion turbine. The LM6000 combustion turbine on FLNG2 will be equipped with SCR.

The projects cited by EPA with lower NO_X limits are land-based projects that utilize SCR. As part of the design process, NFE requested, from the turbine suppliers, the lowest NO_X limit that can be guaranteed for the Project's combustion turbines. With SCR, the FLNG2 GE LM6000PF combustion turbine will meet a NO_X limit of 15 ppmvdc, which is the performance guarantee provided by the SCR vendor.

5. *<u>Proposed NOx BACT limit on Turbines in Power Generating Service</u>: As mentioned above, the application has not attempted to distinguish the infeasibility of SCR or variability in achievable NOx BACT limits on turbines in compression service from turbines in power generating service. As a result, similarly to the proposed compression turbines, the justification for the proposed NOx BACT emissions limit for the turbines in power generating service is also based on the guaranteed NOx emission rate from the turbine vendor and the absence of operating offshore liquefaction facilities. NFE's application proposes a NOx BACT limit for all six industrial power generation turbines (Siemens SGT-400) at 15 ppmvd at 15% O2. Table C-6 of the application identifies turbine NOx BACT determinations for just six facilities. Two of these facilities (Lavaca Bay and Port Delfin) have not been permitted. EPA conducted a cursory review of the RBLC and the latest version of the Texas Commission on Environmental Quality (TCEQ) turbine list for issued permits. Numerous simple-cycle combustion turbines in power generating service have been equipped with DLN and/or SCR for NOx control and apparently achieve BACT limits in the 2 – 25 ppmvd range. For additional reference, TCEQ's June 4, 2019 Tier 1 NOx BACT emission limitation for simple cycle natural gas-fired turbines is between 5 and 9 ppmvd at 15% O2 which is typically achieved with DLN burner, water/steam injection, limiting fuel consumption, or SCR. It is unclear why Table C-6 excludes a significant number of relevant BACT determinations for power generating turbines over the past 10 years. Please provide justification for the exclusion of numerous BACT determinations for simple cycle combustion turbines and include detailed justification on why lower emission limits achieved at onshore facilities (that utilize similar sized turbines in power generating service) were not considered relevant, or if considered, were rejected.*

   As discussed in response to 3a., there is insufficient space to accommodate SCR equipment for the combustion turbines on FLNG1 and the FLNG2 Siemens SGT-400 combustion turbine. Therefore, SCR is not a technically feasible control option for the Siemens SGT-400 combustion turbines.

6. *In reviewing the GE literature for the GE LM6000PF turbine (see: https://www.ge.com/content/dam/gepower/global/en_US/documents/gas/gas-turbines/aero-products-specs/lm6000-fact-sheet-product-specifications.pdf) it appears that depending on net output, the GE LM6000PF with DLE is capable of NOx emissions as low as 15 ppmvd at 15% O2. Please provide additional technical information to support why the refrigeration compression turbines could not achieve a lower NOx emission limit of at least 15 ppmv at 15% O2 with DLN/DLE. Beyond the RBLC, please provide a discussion as to whether NFE has considered and evaluated the availability and feasibility of lower-emitting DLN/DLE technology or any other potentially available upgrades or technological advances to the GE LM6000 turbine*

that could reduce CO/NOx emissions (e.g., autonomous tuning). Is NFE aware of any GE LM6000 turbines installed on offshore platforms?

As discussed in response to 3c, there is expected to be some variability in the characteristics of the natural gas fired in the combustion turbines that impacts the ability the turbine vendors willingness to provide lower emission guarantees. NFE has secured the lowest performance emission guarantees available from the combustion turbine vendors for the Project.

7. *In reviewing the Solar literature for the Solar Taurus 70 turbine (see: https://www.solarturbines.com/en_US/services/equipment-optimization/system-upgrades/safety-and-sustainability/solonox-upgrades.html) it appears that Solar's SoLoNOxTM technology has allowed Solar "to offer a robust 9 ppm NOx, 15 ppm CO, . . . warranty for natural gas fuel. This standard production option is now available for the Taurus 70- 10800. . ." Please provide additional technical information to support why the mechanical drive industrial turbines (Solar Taurus 70) could not achieve a lower NOx or CO emission limit such as 9 ppmvd at 15% O2 and 15 ppmvd respectively.*

   The Solar 70 compressor turbines have been removed from the Project's design. This change has been addressed in the materials provided with this submittal.

8. *Combustion Turbine BACT for CO: As stated previously, EPA requests that the BACT analysis for compression turbines and power generating turbines be conducted separately. On page 4-8 of the application under Step 5 of the CO BACT analysis for combustion turbines, NFE eliminates oxidation catalyst due to economic and environmental impacts. With respect to economic impacts, the application references the BACT analysis conducted in the Port Delfin PSD application that resulted in a cost effectiveness of $6000/ton and states such costs are also not economically feasible for NFE. NFE should conduct its own cost analysis for compression and power generating turbines (with and without waste heat recovery) and justify why such costs are disproportionately high compared to cost of control in recent onshore CO BACT determinations.*

   NFE's engineer has reviewed the requirements for installation of oxidation catalysts on the compressor and power generating turbines and determined that there is insufficient space to accommodate oxidation catalysts. Therefore, oxidation catalysts are not technically feasible for the Project.

9. *With respect to environmental impacts, the application indicates that the use of an oxidation catalyst in the high temperature exhaust of a simple cycle combustion turbine will oxidize 80% of SO2 to SO3 which will be converted to H2SO4 and will result in an increase of H2SO4 emissions of over 36 tons per year. Please provide the basis for this conversion percentage and how the circumstances for the proposed source create greater problems than those at onshore LNG sources. In this discussion, please include the potential remedies to excess H2SO4 generation.*

   There is limited data available for H_2SO_4 emissions from simple cycle turbines with oxidation catalysts, but the Canal Unit 3 project in Massachusetts has an SO_2 limit of 11.1 tpy and an H_2SO_4 limit of 12.0 tpy which indicates 70 percent conversion of sulfur to H_2SO_4. The updated emissions in Attachment D utilizes a 70 percent conversion rate to H_2SO_4.

   NFE has identified no available remedies for the increase in emissions resulting from the use of a high temperature oxidation catalyst on a combustion turbine. Acid gas control is typically done using a wet scrubber but a wet scrubber has never been installed on a combustion turbine due to the high exhaust flow rates and low concentrations of acid gases in the exhaust. The high exhaust temperature from a simple cycle combustion turbine would also preclude the use of a wet scrubber. Further the nature of the deepwater port in an offshore marine environment, eliminates the ready availability of an ample fresh water supply that would be required for use in a wet scrubber.

a. *Proposed CO BACT limit on Turbines in Power Generating Service: The application provides reference to six BACT determinations in Table C-7 for power generating turbines ranging from 25 ppmvd to 36 ppmvd CO at 15% O2. EPA's cursory review of the RBLC identified numerous CO BACT determinations for combustion turbines in power generating service as low as 4 ppmvd. NFE has not provided justification for why only three currently permitted sources (Sabine Pass LNG, Calcasieu Pass LNG, and Plaquemine LNG) were identified in table C-7 or why the proposed CO BACT limit is consistent with recently permitted turbines in power generating service based on site- specific considerations. NFE ultimately proposes CO BACT for power generating turbines (15 ppmvd) based on the vendor guaranteed steady state emission rates and that such determinations are "consistent with the BACT controls for the vast majority of combustion turbines permitted at LNG production facilities." NFE should distinguish itself from the facilities permitted with lower CO BACT limits for power generating turbines. NFE should also acknowledge other facilities permitted with lower BACT limits for CO on power generating turbines and evaluate whether or not such limits are achievable for the proposed project. Ultimately, the BACT limitation must reflect the maximum degree of reduction achievable for each pollutant under the CAA (taking into account technical considerations, or energy, environmental, and economic impacts and other costs). EPA guidance suggests that "While the most effective level of control must be considered in the BACT analysis, different levels of control for a given control alternative can be considered."*

   The projects operating with lower CO emission limits utilize oxidation catalysts to control CO emissions. As discussed in No. #8 above, oxidation catalysts are not technically feasible for the Project's combustion turbines and therefore the proposed combustion turbine vendor emissions guarantees reflect BACT for the Project.

b. *Proposed CO BACT limit on Turbines in Compression Service: The application eliminates oxidation catalyst control under Step 5 and proposes CO BACT for compression turbines based on the vendor guaranteed steady state emission rates and that such determination is "consistent with the BACT controls for the vast majority of combustion turbines permitted at LNG production facilities." Please provide additional justification for the selected CO BACT limit of 25 ppmvd for the NFE DWP project and the infeasibility of utilizing an oxidation catalyst. NFE should acknowledge other facilities permitted with lower BACT limits for CO on compression turbines evaluate whether or not those more stringent limits are technically/economically feasible or achievable. Several RBLC entries for compression turbines propose the use of an oxidation catalyst to control CO emissions. Are there differences in NFE's equipment size / design for refrigeration compression turbines when compared to these onshore turbines that are permitted with oxidation catalyst control?*

   As discussed in No. #8 above, oxidation catalysts are not technically feasible for the Project's combustion turbines and therefore the proposed combustion turbine vendor emissions guarantees reflect BACT for the Project.

c. *BACT Step 1 Control Options for CO: Has NFE considered the use of carbon monoxide turndown (COTD) as a means to reduce CO levels in the turbine exhaust under various load conditions? Please include narrative regarding the elimination of COTD in the permit application.*

   COTD is a technology offered by Siemens that allows for low CO emissions at operating loads below 50 percent. The Project's power generating combustion turbines will be operated at or above 50 percent load and therefore COTD is not an available Step 1 control option for the Project. COTD is not offered for the LM6000 turbine.

d. *The application describes that "steady state operation" of the combustion turbines will be at a minimum of 50% load. EPA notes that on PDF page 284 of the application the Guaranteed CO emission rate for the design, rich, and lean gas cases increase to a maximum of 70 ppm at 50% load on the LM6000PF+ turbine. How does NFE propose to ensure continuous compliance with the 25 ppmvd limit between 50% and 100% load? Please include this information for EPA to evaluate enforceable permit limits for the project.*

During normal operation, the LM6000 compressor turbines will operate at or above 60 percent of rated load and will meet a CO emission rate of 25 ppmvdc.

9. *Proposed VOC BACT on Combustion Turbines: Similarly to CO BACT, the application should provide justification for the elimination of the technically feasible control option (oxidation catalyst) due to economic infeasibility. In addition, for each turbine, confirm with documentation that the proposed VOC BACT rates of 3, 1.4, and 5 ppmvd are all guaranteed at steady-state operating loads between 50% and 100% and how continuous compliance will be ensured.*

As discussed in No. #8 above, oxidation catalysts are not technically feasible for the Project's combustion turbines and therefore the proposed combustion turbine vendor emissions guarantees reflect BACT for the Project. The proposed VOC BACT rates will be met at operating loads above 60% for the LM6000 and 50% for the SGT-400.

10. *Fugitive BACT: Section 4.9 (Fugitive Emission Sources) of the PSD/title V application states that the project's natural gas and LNG handling system will emit VOCs and GHGs due to fugitive equipment leaks from valves, flanges, compressor seals, pumps, and connectors. The application proposes that a leak detection and repair ("LDAR") program will meet BACT for fugitive emissions at the DWP and will consist of an audio, visual and olfactory ("AVO") program. This analysis does not include a five-step BACT analysis identifying potentially applicable control technologies or work practices to reduce VOC/GHG fugitive emissions. Please include a five-step BACT analysis with evaluation of technologies considered to reduce fugitive emissions and the basis for elimination. Technologies may include leakless component technology, leak management programs – LDAR/Enhanced LDAR, best management practices, or good work practices, etc. In addition, please verify if NFE is proposing to utilize TCEQ's 28MID and 28AVO LDAR programs for all VOCs. Is NFE planning to make use of LDEQ's consolidated fugitive LDAR program? As a part of BACT selection, narrative should be included as to which work practice requirements NFE is proposing and why the proposed practices constitute BACT for fugitive emissions*.

Provided in Attachment H is a 5-step BACT analysis for the Project's fugitive emissions. The proposed BACT.

11. *Fugitive Emission Estimates: Please identify any process streams that were excluded from the fugitive emissions calculations and specify which process streams the current component counts account for. Calculations for the LNG stream are apparent, but no mention of fugitives (or speciated emission calculations) related to the acid gas stream, feed gas streams, or mixed refrigerant stream are shown. The permit application needs to present component counts and speciated fugitive emission calculations that include all process streams with potential for fugitive emissions. In addition, please provide the mixed refrigerant speciated composition.*

Does NFE anticipate any refrigerant fugitive emissions, and will the project utilize pressurized refrigerant storage tanks? Are component counts associated with refrigerant storage included in the fugitive emissions? Lastly, please include your analysis of the potential applicability of 40 CFR Part 82. The LDEQ Regulatory Review Analysis Tables (Section 22) do not currently address this regulation.

Each FLNG will include 50 flanged connections in the acid gas handling system and 370 flanged connections in the mixed refrigerant handling system. The Feed gas system will include 2429 flanged gas connections. Fugitive emissions resulting from these gas handling systems have been estimated and included with the revised emission calculations provided with this response.

12. *GHG BACT: The application states in section 4.10 that the BACT analysis for GHG emissions were evaluated collectively for the Project (principally as CO2, CH4 and N2O) and GHG BACT is ultimately proposed as complying with the TPY limits in table 2-9. The application notes that combustion turbines comprise over 80% of the project's total GHG emissions, and the acid gas thermal oxidizers comprise another 12% of the project's GHG emissions. NFE concludes that GHGs from other emission sources are insignificant compared to the combustion turbines and thermal oxidizer and are not considered in the analysis. NFE should include a top-down analysis of BACT for each affected emission unit (or include discussion of each unit type in its combined analysis) which identifies all available control technologies potentially suitable for the affected units including, but not limited to, flue gas carbon capture and storage, low carbon fuel (fuel selection), design and operational energy efficiency (including waste heat recovery), good combustion, operating and maintenance practices, combustion intake air cooling, and electric- drive compressors. So the record is clear, ensure that the GHG BACT analysis includes a top- down analysis for combustion turbines for refrigeration & feed gas compression, combustion turbines for electric power generation, thermal oxidizers, warm and cold flares, package boilers, and emergency generator engines. NFE needs to provide narrative in the permit application describing the operating practices, efficiency measures and associated compliance monitoring proposed to serve as BACT and minimize GHG emissions for each group of units under review. In addition, please provide justification for why an evaluation of more efficient types of combustion turbines (i.e., combined cycle) were not considered or are technically infeasible.*

    Attachment H includes a 5-step GHG BACT analysis.

13. *MSS Emissions/BACT: Under section 2.4.1.2 for combustion turbine startup/shutdown operations, the application states that startup and shutdown emissions "may, for some pollutants, result in an increase in short-term (lb/hr) emission rates." The application further summarizes the VOC, NOx and CO emissions associated with SU/SD for combustion turbines based on lbs of each pollutant per startup or shutdown event in Table 2-3. The application also notes that "These emissions reflect expected typical performance from the equipment vendors but are not guaranteed emission rates." and that "This application assumes that the short duration increases in emissions during SU/SD will not be additive to the potential emissions as the increases will be small and expected to be offset by combustion turbine downtime." Based on this language, it appears that the application is proposing to exceed the normal operation emission rates during startup and shutdown and does not provide emission rates for turbines during such operating scenarios. If startup and shutdown emissions are not included in the proposed BACT limits (currently proposed to apply only during steady state operations), then an alternative BACT analysis is needed that will apply during startup and shutdown emissions. BACT emission limitations must be met continuously under all operating scenarios and the startup and shutdown emissions need to be authorized in the permit since these emissions may exceed the steady-state emission rates.*

    For each criteria pollutant, include the maximum worst-case lb/hr emission rate expected (and the basis/methodology for such calculations) for the SU/SD operating scenario for each combustion turbine. In *addition, as required by the Emissions Inventory Questionnaire (EIQ) forms, please complete one EIQ for ". . . Each alternate operating scenario that a source may operate under. Some common scenarios are: . . . 2. Sources that have Startup/Shutdown max lb/hr emission rates higher than the max lb/hr for normal operating conditions would need an EIQ for the Startup/Shutdown emission rates for those sources." Please include language regarding the purpose of startup and shutdowns, how often they will occur, the duration of each event, and annual hours of SU/SD.*

Table 2-3 in the application provided emissions during a startup or shutdown (SUSD) event in units of pounds emitted per event consistent with vendor provided data. Based upon the estimated duration of an event, the maximum pounds emitted in an hour with a SUSD event was calculated assuming that the remainder of the hour was at full load steady state operation. These emissions are provided in the table below and provided as an alternate operating scenario in EIQ forms provided in Attachment I. Per the EIQ instructions, SUSD emissions are only presented for those pollutants with hourly emissions above their respective maximum steady state rate.

Combustion Turbine Startup and Shutdown Emissions (lbs/hr)			
Pollutant	**Operating Condition**	**GE LM6000**	**Siemens SGT-400**
Event Duration (mins)		9	3
NOx	Steady State Rate (lb/hr)	44.5	9.92
	Steady State (lbs/event)	37.8	9.42
	SUSD Rate (lb/hr)	38.6	9.72
CO	Steady State Rate (lb/hr)	27.1	6.04
	Steady State (lbs/event)	23.0	5.74
	SUSD Rate (lb/hr)	33.3	6.8
VOC	Steady State Rate (lb/hr)	1.86	0.35
	Steady State (lbs/event)	1.6	0.33
	SUSD Rate (lb/hr)	2.28	0.46

During normal plant operation, all of the Project's combustion turbines will be in operation. Startups and shutdowns will occur due to planned maintenance and unplanned malfunctions that require a combustion turbine to be shutdown and restarted. For permitting purposes, NFE assumes that the number of SUSD events per year will be 26 events per turbine per year. The annual emissions will not be impacted by the SUSD emission rates as the downtime associated with shutdowns is expected to offset the minor short-term increase in CO and VOC emissions during transient operation.

<u>MSS BACT Cont.:</u> The application includes a short description at Step 5 of the BACT determination for each combustion turbine stating that the proposed BACT rates apply during steady state operation at or above 50 percent of rated operating load. And that the "Emissions during SU/SD will be limited through good operating practices to minimize the duration of SU/SD events to achieve the steady state BACT rate as quickly as possible." Please provide additional detail of the "good operating practices" proposed for BACT during MSS.

The combustion turbines will be started and shutdown in accordance with vendor recommendations to ensure proper combustion during the events. The combustion turbines will switch to low-NO_X combustion mode at the lowest operating load recommended by the vendor to minimize NO_X emissions.

14. <u>*Proposed Thermal Oxidizer BACT:*</u>
    a. *NOx: NFE's proposed NOx BACT emission rate for Acid Gas Thermal Oxidizers is 0.10 lb/MMBtu. Under Step 5, the justification for the proposed NOx BACT limit appears to be based on the lowest guaranteed NOx emission rate provided by the vendor. The application does not explain why NOx BACT emission rates for similar acid gas thermal oxidizers located at onshore LNG export facilities with notably lower NOx limits are not meaningful to NFE's BACT analysis. While it is not mandatory to select a specific NOx limit as BACT solely because another similar source has done so, the basis for selecting a less stringent limit should be documented in the permit record for evaluation.*

       The RBLC entries provided in Table C-16 identified a total of 7 permitted facilities with thermal oxidizers. The Lake Charles LNG Export Terminal (PSD-LA-838) is listed as 50 lb/MMscf which appears to be roughly half the estimated BACT limit currently proposed by NFE. EPA requests justification for the exclusion of numerous BACT determinations for thermal oxidizers at other sources and reasoned justification for why they were not considered relevant, or if considered, were rejected. EPA's cursory review of the RBLC and other permitted BACT limits identified additional thermal oxidizers with lower proposed BACT NOx limits as low as 0.035 lb/MMBtu with multiple at 0.06 lb/MMBtu. See Alaska Gasline Liquefaction Plant (0.055 lb/MMBtu), Corpus Christi Liquefaction Stage III (0.06 lb/MMBtu), Port Arthur LNG (0.06 lb/MMBtu), Freeport LNG Pretreatment (0.06 lb/MMBtu), Chevron Orange Polyethylene (0.06 lb/MMBtu), Occidental Chemical (0.06 lb/MMBtu), etc. EPA also notes that TCEQ's current Tier I BACT Requirements for Chemical Sources for NOx emissions from Thermal Oxidizers is 0.06 lb/MMBtu or less.

       Beyond manufacturer guarantee, the application should provide reasoned justification for why 0.10 lb/MMBtu is considered BACT for the proposed thermal oxidizers or why the waste stream through thermal oxidizers at other plants is materially different as to affect the achievability of the aforementioned limits at the proposed project.

       Lastly, please explain how emissions will be routed from various processes when the Thermal Oxidizer is down for maintenance and provide an estimate of annual thermal oxidizer downtime.

       A thermal oxidizer with a NO_X emission rate of 0.10 lb/MMBtu is required to meet the construction schedule of the Project. Although lower NO_X combustion turbines are available, these are custom designed units that cannot be procured in time to satisfy the Project's schedule.

       The process will be shutdown when the thermal oxidizer is down for maintenance.

15. <u>*Proposed Flare BACT:*</u>
    a. *The BACT analysis does not acknowledge Air- or Steam-Assisted flares. Please provide narrative regarding the feasibility of these alternatives. In addition, specify if the proposed flares are air-assisted, steam-assisted, or non-assisted and include additional detail with respect to the proposed flare design.*

       There is no steam on the deepwater port platforms to use steam assisted flares. The dry flares will be air assisted but the wet flares do not require air assistance. There will be no difference in emissions performance between the dry and wet flares.

    b. *NOx: NFE's proposed NOx BACT emission rate for all flares is 0.138 lb/MMBtu. The application also identifies several other BACT determinations for dry/wet flares at LNG facilities permitted at 0.068* *lb/MMBtu with no discussion regarding the infeasibility of these limits based on NFE's waste stream. Provide an explanation of the proposed emission rate and why it is more conservative and/or representative of the site-specific flaring for the proposed project than the lower AP-42-based rate. Provide citation to the TCEQ guidance document relied on for NOx and CO flare emission factors and discuss the reliability of such factors.*

The flare vendor has agreed to guarantee a NO_X emission rate of 0.068 lb/MMBtu consistent with recent BACT determinations for dry and wet flares at LNG facilities. The Project's potential emissions have been updated with this revised BACT emission rate.

c. *VOC: Application page 4-21 states that for all flares VOC emissions are ". . . based upon 99 percent destruction of the VOCs in the gas based upon the equipment vendor emissions guarantee." Please provide a copy of the vendor guarantee for this destruction rate when combusting C1-C3 compounds and C4+ compounds. Additionally, EPA requests reasoned justification for how NFE plans to ensure the elevated flare continuously meets 99% DRE at all times regardless of flow conditions, gas composition, or meteorological conditions.*

   Provided in Attachment J is vendor confirmation of 99 percent control for the gases delivered to the flares based upon design criteria for the Project.

d. *In Appendix B (Emission Calculations), the footnote for all flares states that the "CH4 emission factor rate assumes 99.9% destruction of C1, C2, and C3 compounds (CH4, C2H6, C3H8) present in gas sent to flare." Provide reasoned justification for this proposed destruction efficiency and how such an assumption can be ensured through enforceable permit limits.*

   CH_4 emissions have been revised based upon a 99% destruction consistent with VOC emissions. The revised emissions in Attachment D reflect this change.

e. *Describe in detail how emissions will be controlled during purging of inert marine vessels. Does NFE anticipate the need for supplemental auxiliary fuel during these events to meet the minimum NHV requirements of 60.18? If so, please specify how these fuel requirements are reflected in current emission calculations. How many hours would each flare receive purge gas from inerted vessels per year?*

   Purging of marine vessels is not part of the Project's design. Receiving vessels will evacuate their storage tanks prior to receiving LNG from the Project.

f. *How many hours per year will the flares receive BOG when the liquefaction trains are down?*

   Boil off gas (BOG) will be controlled by the gas combustion unit (GCU) when the liquefaction trains are down. The GCU is estimated to operate 144 hours per year.

16. *Emergency Combustion Engine BACT (Emergency Generators & Firewater Pumps):*
    a. *GHG: As mentioned in the GHG section above, include a top-down BACT analysis for GHG emissions from emergency engines and discuss feasible options i.e., thermally efficient equipment, good combustion practices, limited hours of operation.*

       A 5-step BACT analysis for GHG emissions from the emergency engines is provided in Attachment H.

    b. *Include manufacturer documentation on the Clarke C18 and Clarke C32 emergency engines.*

       The emergency fire pump engine models have been changed since submission of the permit application. Provided in Attachment K is the manufacturer documentation for Clarke UFAC28 and

Clarke UFAD38 emergency fire pump engines. The revised emission calculations in Attachment F reflect this change.

17. Storage Tank BACT:
    a. *VOC: The application identifies 62 non-insignificant fuel oil storage tanks with capacity greater than 10,000 gallons. The application should include a top-down BACT analysis for VOC emissions from storage tanks and evaluate potential VOC control options (i.e., fixed/floating roof tanks, submerged fill, good work practices, white paint, closed vent system, etc). Discuss quantity of emissions, technical and economic feasibility of controls, and significance of reductions from the application of controls on storage tanks with vapor pressure <0.5 psia.*

    As indicated previously in the response to EPA request General 2.j., NFE requests that these storage tanks be exempt in accordance with LAC 33:III 501(B)5. As such, BACT would not be not required.

18. Package Boiler BACT:
    a. *NOx: The analysis identifies the technical feasibility of Low NOx Burners on the package boilers, but no cost analysis appears to have been conducted. Therefore, the analysis should explain the basis for rejection of this control technology as BACT.*

    The boilers on the FSU are small package boilers and retrofit of the package boilers with low-NO_X burners (LNBs) will not achieve meaningful emission reductions. A search of the RBLC for distillate oil fired boilers rated less than 10 million Btu per hour did not identify any units equipped with LNBs or any other type of NO_X control. The Project has proposed good combustion practices, which is consistent with all other BACT determinations for similarly sized boilers.

Should you have any questions, please contact me at 281-704-5391 or khassan@newfortressenergy.com.

Respectfully submitted,

New Fortress Energy

Komi Hassan

Komi Hassan, Vice President, Environment

Attachments

A. EPA Part 71 Forms
B. LDEQ Application for Approval of Emissions of Air Pollutants from Part 70 Sources Form
C. Thermal Oxidizer and Flare CAM Plans
D. Detailed Site Layout Figures
E. Detailed Process Description
F. Emission Calculations
G. Combustion Turbine BACT Analysis
H. GHG BACT Analysis
I. Combustion Turbine SUSD EIQ Forms
J. Flare Vendor VOC Control Specification
K. Clarke Emergency Fire Pump Engine Specifications

ATTACHMENT A

EPA PART 71 FORMS

United States Environmental Protection Agency

OMB No. 2060-0336, Expires 11/30/2022

Federal Operating Permit Program (40 CFR Part 71)

CERTIFICATION OF TRUTH, ACCURACY, AND COMPLETENESS (CTAC)

This form must be completed, signed by the "Responsible Official" designated for the facility or emission unit, and sent with each submission of documents (i.e., application forms, updates to applications, reports, or any information required by a part 71 permit).

A. Responsible Official

Name: (Last) __Hassan_______________ (First) __Komi________________ (MI) ____

Title ___Vice President____

Street or P.O. Box __111 W 19th St, 2nd Floor _________________________________

City __New York_________________________ State _NY__ ZIP _10011___ - _____

Telephone (518) _268 - 7400___ Ext. ______ Facsimile (____) ____ - ________

B. Certification of Truth, Accuracy and Completeness (to be signed by the responsible official)

I certify under penalty of law, based on information and belief formed after reasonable inquiry, the statements and information contained in these documents are true, accurate and complete.

Name (signed) Komi Hassan

Name (typed) __Komi Hassan_________________ Date: 02 / 28 / 2023

United States Environmental Protection Agency

OMB No. 2060-0336, Expires 11/30/2022

Federal Operating Permit Program (40 CFR Part 71)
GENERAL INFORMATION AND SUMMARY (GIS)

A. Mailing Address and Contact Information

Facility name _Louisiana FLNG Deep Water Port______________________________

Mailing address: Street or P.O. Box _111 W 19th St, 2nd Floor______________________

City __New York__________________ State _NY______ ZIP __10011_________-________

Contact person: _Komi Hassan_______________ Title ___Vice President_______________

Telephone (_281__) _704____ - __5391______ Ext. _________

Facsimile (______) ________ - ___________

B. Facility Location

Temporary source? ___Yes _X_No Plant site location ______________________________

___West Delta Block 38, 16 nautical miles ("nm") off the southeast coast of Grand Isle, Louisiana.___

City __Plaquemines Parish________ State__LA_ County________________ EPA Region_6__

Is the facility located within:

Indian lands? ___YES _X__ NO An offshore source in federal waters? _X__YES ___ NO

Non-attainment area? ___ YES _X__NO If yes, for what air pollutants? _______________

Within 50 miles of affected State? _X_ YES __ NO If yes, What State(s)? _____________

C. Owner

Name _New Fortress Energy_Louisiana FLNG LLC Street/P.O. Box _111 W 19th St, 2nd Floor ____

City ___New York_______________________________ State_NY___ ZIP_10011____ - ________

Telephone (_516__) _268__ - __7400_____ Ext_________

D. Operator

Name ___Same as Owner__________________ Street/P.O. Box ___________________________

City ____ State ______ ZIP _________ - _______

Telephone (_____) ______ - ___________ Ext__________

E. Application Type

Mark only one permit application type and answer the supplementary question appropriate for the type marked.

_X__Initial Permit ___ Renewal ___ Significant Mod ___ Minor Permit Mod(MPM)

___ Group Processing, MPM ___ Administrative Amendment

For initial permits, when did operations commence? _____ /_____ /_____ (NOT YET CONSTRUCTED)

For permit renewal, what is the expiration date of current permit? _____/____/_____

F. Applicable Requirement Summary

Mark the types of applicable requirements that apply:

_X_ SIP ___ FIP/TIP _X_ PSD ___Non-attainment NSR

___ Minor source NSR _X_ Section 111 ___ Phase I acid rain ___Phase II acid rain

___ Stratospheric ozone ___ OCS regulations _X__ NESHAP ___ Sec. 112(d) MACT

___ Sec. 112(g) MACT ___ Early reduction of HAP ___ Sec 112(j) MACT ___ RMP [Sec.112(r)]

___ Section 129 ___ NAAQS, increments or visibility but for temporary sources (This is rare)

Is the source subject to the Deepwater Port Act? _X__YES ___NO

Has a risk management plan been registered? ___YES _ __NO Agency ____________________

Phase II acid rain application submitted? ___YES ___NO If YES, Permitting Authority ____________

G. Source-Wide PTE Restrictions and Generic Applicable Requirements

Cite and describe any emissions-limiting requirements and/or facility-wide "generic" applicable requirements.

Deepwater Port Act of 1974, as amended (33 U.S. Code Chapter 29)
LAC 33:III 509 (Prevention of Significant Deterioration)
LAC 33:III 2113 (Housekeeping)
LAC 33:III Chapter 9 (General Regulations on Control of Emissions and Emission Standards)
LAC 33:III Chapter 29 (Odor Regulations)
LAC 33:III Chapter 56 (Prevention of Air Pollution Emergency Episodes)
40 CFR 98 (Greenhouse Gas Reporting)

H. Process Description

List processes, products, and SIC codes for the facility.

Process	Products	SIC
Liquefaction	Liquefied Natural Gas	4925

I. Emission Unit Identification

Assign an emissions unit ID and describe each emissions unit at the facility. Control equipment and/or alternative operating scenarios associated with emissions units should by listed on a separate line. Applicants may exclude from this list any insignificant emissions units or activities.

Emissions Unit ID	Description of Unit
FLNG1 CT	Floating Liquefied Natural Gas Plant 1 (FLNG1) Compressor Turbine (GE LM 6000)
FLNG2 CT1	Floating Liquefied Natural Gas Plant 2 (FLNG2) Compressor Turbine (GE LM 6000)
FLNG1 PGT1	FLNG1 Power Generating Turbine 1 (Siemens SGT-400)
FLNG1 PGT2	FLNG1 Power Generating Turbine 2 (Siemens SGT-400)
FLNG1 PGT3	FLNG1 Power Generating Turbine 3 (Siemens SGT-400)
FLNG2 PGT1	FLNG2 Power Generating Turbine 1 (Siemens SGT-400)
FLNG2 PGT1	FLNG2 Power Generating Turbine 2 (Siemens SGT-400)
FLNG2 PGT1	FLNG2 Power Generating Turbine 3 (Siemens SGT-400)
FLNG1 TO	FLNG1 Acid Gas Thermal Oxidizer
FLNG2 TO	FLNG2 Acid Gas Thermal Oxidizer
FLNG1 CF	FLNG1 Dry Flare
FLNG1 WF	FLNG1 Wet Flare
FLNG2 CF	FLNG2 Dry Flare
FLNG2 WF	FLNG2 Wet Flare
FLNG1 EDG1	FLNG1 Emergency Generator Engine 1 (CAT 3516)
FLNG1 EDG2	FLNG1 Emergency Generator Engine 2 (CAT 3516)
FLNG1 EDG3	FLNG1 Emergency Generator Engine 3 (CAT 3516)
FLNG1 EDG4	FLNG1 Emergency Generator Engine 4 (CAT 3516)
FLNG1 EDG5	FLNG1 Emergency Generator Engine 5 (CAT 3516)
FLNG1 EDG6	FLNG1 Emergency Generator Engine 6 (CAT 3516)
FLNG1 EDG7	FLNG1 Emergency Generator Engine 7 (CAT 3512)

FLNG2 EDG1	FLNG2 Emergency Generator Engine 1 (CAT C18)
FLNG2 EDG2	FLNG2 Emergency Generator Engine 2 (CAT C18)
FLNG2 EDG3	FLNG2 Emergency Generator Engine 3 (CAT 3512)
FLNG2 EDG4	FLNG2 Emergency Generator Engine 4 (CAT 3512)
FLNG2 EDG5	FLNG2 Emergency Generator Engine 5 (CAT 3512)
FLNG2 EDG6	FLNG2 Emergency Generator Engine 6 (CAT 3512)
FLNG2 EDG7	FLNG2 Emergency Generator Engine 7 (CAT 3512)
FLNG2 FP1	FLNG2 Emergency Fire Pump Engine 1 (Clarke UFAC28)
FLNG2 FP2	FLNG2 Emergency Fire Pump Engine 2 (Clarke UFAC28)
FLNG2 FP3	FLNG2 Emergency Fire Pump Engine 3 (Clarke UFAC28)
FLNG2 FP4	FLNG2 Emergency Fire Pump Engine 4 (Clarke UFAC28)
FLNG2 FP5	FLNG2 Emergency Fire Pump Engine 5 (Clarke UFAC28)
FLNG2 FP6	FLNG2 Emergency Fire Pump Engine 6 (Clarke UFAC28)
FLNG2 FP7	FLNG2 Emergency Fire Pump Engine 7 (Clarke UFAD38)
FLNG2 FP8	FLNG2 Emergency Fire Pump Engine 8 (Clarke UFAD38)
FSU EDG	FSU - Emergency Generator Engine
FSU Boiler 1	FSU - Package Boiler #1
FSU Boiler 1	FSU - Package Boiler #2
FSU GCU	FSU – Gas Combustion Unit

J. Facility Emissions Summary

Enter potential to emit (PTE) for the facility as a whole for each regulated air pollutant listed below. Enter the name of the single HAP emitted in the greatest amount and its PTE. For all pollutants, stipulations to major source status may be indicated by entering "major" in the space for PTE. Indicate the total actual emissions for fee purposes for the facility in the space provided. Applications for permit modifications need not include actual emissions information.

NOx __673.5____ tons/yr VOC __41.0_____ tons/yr SO2 __106.7____ tons/yr

PM-10 __82.9_____ tons/yr CO __669.3____ tons/yr Lead _0.0004_____ tons/yr

Total HAP __10.9______ tons/yr

Single HAP with greatest amount __Formaldehyde____________ PTE __6.3___ tons/yr

Total of regulated pollutants (for fee calculation), Sec. F, line 5 of form FEE _N/A__ tons/yr

K. Existing Federally-Enforceable Permits (NOT APPLICABLE)

Permit number(s) ______________ Permit type _____________ Permitting authority __________

Permit number(s) _________________ Permit type _____________ Permitting authority _________

L. Emission Unit(s) Covered by General Permits (NOT APPLICABLE)

Emission unit(s) subject to general permit ____

Check one: ___ Application made ___ Coverage granted

General permit identifier ______________________________ Expiration Date ____/____/____

M. Cross-referenced Information

Does this application cross-reference information? ___ YES _X_ NO (If yes, see instructions)

INSTRUCTIONS FOLLOW

United States Environmental Protection Agency

OMB No. 2060-0336, Expires 11/30/2022

Federal Operating Permit Program (40 CFR Part 71)

INITIAL COMPLIANCE PLAN AND COMPLIANCE CERTIFICATION (I-COMP)

SECTION A - COMPLIANCE STATUS AND COMPLIANCE PLAN

Complete this section for each unique combination of applicable requirements and emissions units at the facility. List all compliance methods (monitoring, recordkeeping and reporting) you used to determine compliance with the applicable requirement described above. Indicate your compliance status at this time for this requirement and compliance methods and check “YES” or “NO” to the follow-up question.

Emission Unit ID(s):
FLNG1 – CT, FLNG2 – CT1, FLNG1 - PGT1, FLNG1 – PGT2, FLNG1 – PGT3, FLNG2 - PGT1, FLNG2 – PGT2, FLNG2 – PGT3, FLNG1 – TO, FLNG2 – TO, FLNG1-EDG1, FLNG1-EDG2, FLNG1-EDG3, FLNG1-EDG4, FLNG1-EDG5, FLNG1-EDG6, FLNG1-EDG7, FLNG2-EDG1, FLNG2-EDG2, FLNG2-EDG3, FLNG2-EDG4, FLNG2-EDG5, FLNG2-EDG6, FLNG2-EDG7, FLNG2-FP1, FLNG2-FP2, FLNG2-FP3, FLNG2-FP4, FLNG2-FP5, FLNG2-FP6, FLNG2-FP7, FLNG2-FP8, FSU-Boiler1, FSU-Boiler2, FSU-EDG, FSU-GCU

Applicable Requirement (Describe and Cite)

LAC 33:III.Chapter 13, 1313C. No person shall cause, suffer, allow or permit the emission of particulate matter to the atmosphere from any fuel burning equipment in excess of 0.6 pounds per MMBtu of heat input.

Compliance Methods for the Above (Description and Citation):

LAC 33:III.Chapter 13, 1309A. The methods listed in LAC 33:III.1503.D.2, Table 4 or such equivalent methods as may be approved by the department shall be utilized to determine particulate concentrations in stack gases.

Compliance Status:

___ In Compliance: Will you continue to comply up to permit issuance? ____Yes ____No

___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No

_X_ Future-Effective Requirement: Do you expect to meet this on a timely basis? _X__Yes ____No

Emission Unit ID(s):
FLNG1 – CT, FLNG2 – CT1

Applicable Requirement (Description and Citation):
LAC 33:III.Chapter 15, 1503C. No person shall discharge gases from the subject sources that contain concentrations of SO 2 in excess of 2,000 parts per million (ppm) by volume at standard conditions (three hour average), or any applicable Federal NSPS or NESHAP emission limitation, whichever is more stringent. Single point sources that emit or have the potential to emit less than 250 tons per year of sulfur compounds measured as sulfur dioxide may be exempted from the 2,000 ppm(v) limitation by the administrative authority.

Compliance Methods for the Above (Description and Citation):
Compliance with 40 CFR 60, NSPS Subpart KKKK SO2 limit will satisfy compliance with this limit.
Exempt from fuel sulfur monitoring in accordance with 40 CFR 60.6345

Compliance Status:

___ In Compliance: Will you continue to comply up to permit issuance? ____Yes ____No

___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No

_X__ Future-Effective Requirement: Do you expect to meet this on a timely basis? _X_Yes _____No

---

Emission Unit ID(s):
FLNG1 – TO, FLNG2 – TO

Applicable Requirement (Description and Citation):
LAC 33:III.Chapter 15, 1503C. No person shall discharge gases from the subject sources that contain concentrations of SO 2 in excess of 2,000 parts per million (ppm) by volume at standard conditions (three hour average), or any applicable Federal NSPS or NESHAP emission limitation, whichever is more stringent. Single point sources that emit or have the potential to emit less than 250 tons per year of sulfur compounds measured as sulfur dioxide may be exempted from the 2,000 ppm(v) limitation by the administrative authority.

Compliance Methods for the Above (Description and Citation):
Initial compliance test LAC 33:III.Chapter 15, 1503D and reporting of results 1513.A.2. Exempt from continuous compliance monitoring LAC 33:III.Chapter 15, 1511D.2.

Compliance Status:

___ In Compliance: Will you continue to comply up to permit issuance? ____Yes ____No

___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No

_X__ Future-Effective Requirement: Do you expect to meet this on a timely basis? _X_Yes _____No

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Emission Unit ID(s):
FLNG1 – CT, FLNG2 – CT1, FLNG1 - PGT1, FLNG1 – PGT2, FLNG1 – PGT3, FLNG2 - PGT1, FLNG2 – PGT2, FLNG2 – PGT3

Applicable Requirement (Description and Citation):
40 CFR 60.4320(a) and Table 1 to Subpart KKKK of Part 60. NOx limit of 25 ppm at 15 percent O2 or 150 ng/J of useful output (1.2 lb/MWh).

Compliance Methods for the Above (Description and Citation):
Initial performance test in accordance with 40 CFR 60.4400.
Continuous monitoring of low-NO_X operation in accordance with 40 CFR 60.4340(b)(2)(ii).
Operate and maintain air pollution control equipment and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction in accordance with 40 CFR 60.4333.

Semiannual excess emissions reports in accordance with 40 CFR 60.7(c) and 60.4375 and 60.4395

Compliance Status:

___ In Compliance: Will you continue to comply up to permit issuance? ____Yes ____No

___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No

_X__ Future-Effective Requirement: Do you expect to meet this on a timely basis? _X_Yes _____No

Emission Unit ID(s):
FLNG1 – CT, FLNG2 – CT1, FLNG1 - PGT1, FLNG1 – PGT2, FLNG1 – PGT3, FLNG2 - PGT1, FLNG2 – PGT2, FLNG2 – PGT3

Applicable Requirement (Description and Citation):
40 CFR 60.4330(a)(2). Turbine must not burn fuel which contains total potential sulfur emissions in excess of 26 ng SO2/J (0.060 lb SO2/MMBtu) heat input.

Compliance Methods for the Above (Description and Citation):
Fuel sulfur may be monitored in accordance with 40 CFR 60.4360 or 40 CFR 60.4370(b) and (c). in accordance with 40 CFR 60.4365(b). The Project may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO2/J (0.060 lb SO2/MMBtu) heat input if representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO2/J (0.060 lb SO2/MMBtu) heat input for continental areas.
Records of fuel sulfur content will be maintained in accordance with 40 CFR 60.4360, 40 CFR 60.4365, and/or 40 CFR 60.4370
Semiannual excess emissions reports in accordance with 40 CFR 60.7(c) and 60.4375 and 60.4395

Compliance Status:

___ In Compliance: Will you continue to comply up to permit issuance? ____Yes ____No

___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No

_X__ Future-Effective Requirement: Do you expect to meet this on a timely basis? _X_Yes _____No

Emission Unit ID(s):
FLNG1-TO, FLNG2-TO, FLNG1-EDG1, FLNG1-EDG2, FLNG1-EDG3, FLNG1-EDG4, FLNG1-EDG5, FLNG1-EDG6, FLNG1-EDG7, FLNG2-EDG1, FLNG2-EDG2, FLNG2-EDG3, FLNG2-EDG4, FLNG2-EDG5, FLNG2-EDG6, FLNG2-EDG7, FLNG2-FP1, FLNG2-FP2, FLNG2-FP3, FLNG2-FP4, FLNG2-FP5, FLNG2-FP6, FLNG2-FP7, FLNG2-FP8, FSU-EDG, FSU-Boiler1, FSU-Boiler2, FSU-GCU

Applicable Requirement (Description and Citation):
LAC 33:III. Chapter 11. 1101.A. Except as specified in LAC 33:III.1105, the emission of smoke generated by the burning of fuel or combustion of waste material in a combustion unit, including the incineration of industrial, commercial, institutional and municipal wastes, shall be controlled so that the shade or appearance of the emission is not darker than 20 percent average opacity, except that such emissions may have an average opacity in excess of 20 percent for not more than one six minute period in any 60 consecutive minutes.

Compliance Methods for the Above (Description and Citation):

Opacity shall be determined using method 9 of 40 CFR Part 60, appendix A. LAC 33:III. Chapter 11. 1106.A

Compliance Status:

___ In Compliance: Will you continue to comply up to permit issuance? ____Yes ____No

___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No

_X__ Future-Effective Requirement: Do you expect to meet this on a timely basis? _X_Yes _____No

Emission Unit ID(s):
FLNG1-CF, FLNG1-WF, FLNG2-CF, FLNG2-WF

Applicable Requirement (Description and Citation):
LAC 33:III. Chapter 11. 1105.A. The emission of smoke from a flare or other similar device used for burning in connection with pressure valve releases for control over process upsets shall be controlled so that the shade or appearance of the emission does not exceed 20 percent opacity (LAC 33:III.1503.D.2, Table 4) for a combined total of 6 hours in any 10 consecutive days. If it appears the emergency cannot be controlled in six hours, SPOC shall be notified by the emitter in accordance with LAC 33:I.3923 as soon as possible after the start of the upset period. Such notification does not imply the administrative authority will automatically grant an exemption to the source(s) of excessive emissions.

Compliance Methods for the Above (Description and Citation):
Opacity shall be determined using method 9 of 40 CFR Part 60, appendix A. LAC 33:III. Chapter 11. 1106.A

Compliance Status:

___ In Compliance: Will you continue to comply up to permit issuance? ____Yes ____No

___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No

___ Future-Effective Requirement: Do you expect to meet this on a timely basis? ____Yes _____No

Emission Unit ID(s):
FLNG1-EDG1, FLNG1-EDG2, FLNG1-EDG3, FLNG1-EDG4, FLNG1-EDG5, FLNG1-EDG6, FLNG1-EDG7

Applicable Requirement (Description and Citation):
40 CFR 63.6603(a) and 63.6640(a): Comply with the requirements in Table 2d to this subpart.
a. Change oil and filter every 500 hours of operation or annually, whichever comes first;
b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and
c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

40 CFR 63.6604(b): Use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel

40 CFR 63.6605(b): At all times you must operate and maintain the engine, including associated

monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

40 CFR 63.6605(a): You must be in compliance with the operating limitations in this subpart that apply to you at all times.

40 CFR 63.6625(e): operate and maintain the engine according to the manufacturer's written instructions or develop your own maintenance plan which must provide, to the extent practicable, for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.

40 CFR 63.6625(h): minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to this subpart apply.

40 CFR 63.6625(i): you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Table **2d** to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table **2d** to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content.

§ 63.6640(f): If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1) through (4) of this section. In order for the engine to be considered an emergency stationary RICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in nonemergency situations for 50 hours per year, as described in paragraphs (f)(1) through (4) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (4) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non- emergency engines.

(1) There is no time limit on the use of emergency stationary RICE in emergency situations.

(2) You may operate your emergency stationary RICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

(3) Emergency stationary RICE located at major sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non- emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or

to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(4) Emergency stationary RICE located at area sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non- emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraphs (f)(4)(i) and (ii) of this section, the 50 hours per year for nonemergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) Prior to May 3, 2014, the 50 hours per year for non-emergency situations can be used for peak shaving or nonemergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engine is operated as part of a peak shaving (load management program) with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system.

(ii)The 50 hours per year for nonemergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator.

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

Compliance Methods for the Above (Description and Citation):
40 CFR 63.6625(f): install a non-resettable hour meter

§ 63.6655(a): **Y**ou must keep the records described in paragraphs (a)(2), (a)(4) and (a)(5) of this section.
(2) Records of the occurrence and duration of each malfunction of operation (*i.e.,* process equipment) or the air pollution control and monitoring equipment.
(4) Records of all required maintenance performed on the monitoring equipment.
(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with §63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

§ 63.6655(e)(2): You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE according to your own maintenance plan, as applicable.

§ 63.6655(f)(2): You must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engine is used for the purposes specified in § 63.6640(f)(2)(ii) or (iii) or § 63.6640(f)(4)(ii), the owner or operator must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation for these purposes.

Compliance Status:

___ In Compliance: Will you continue to comply up to permit issuance? ____Yes ____No

___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No

_X__ Future-Effective Requirement: Do you expect to meet this on a timely basis? _X_Yes _____No

Emission Unit ID(s):
FLNG2-EDG1, FLNG2-EDG2, FLNG2-EDG3, FLNG2-EDG4, FLNG2-EDG5, FLNG2-EDG6, FLNG2-EDG7, FSU-EDG

Applicable Requirement (Description and Citation):
40 CFR 60.4205(b) and Table 3 to Subpart IIII of 40 CFR 60. Owners and operators of 2007 model year or later emergency CI ICE units must comply with the following emission standards based on the rated power of the unit:
Rated Power: kW > 560 kW (hp > 750 hp)

- NMHC+NOx: 6.4 g/kW-hr (4.8 g/hp-hr)
- CO: 3.5 g/kW-hr (2.6 g/hp-hr)
- PM: 0.20 g/kW-hr (0.15 g/hp-hr)

Compliance Methods for the Above (Description and Citation):
40 CFR 60.4211(c). Owners and operators must comply with this subpart by purchasing an engine certified to the emission standards in 40 CFR 60.4205(b) The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section.
40 CFR 60.4206. Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in 40 CFR 60.4205 over the entire life of the engine
40 CFR 60.4207(b). Owners and operators must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.
40 CFR 60.4211(a). Owner or operators must maintain the engines as follows: (1) operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions; (2) change only those emission-related settings that are permitted by the manufacturer; and (3) meet the requirements of 40 CFR part 1068, as they apply to you
40 CFR 60.4211(f). In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (3) of this section, is prohibited.
40 CFR 60.4211(f)(1). There is no time limit on the use of emergency stationary ICE in emergency situations.
40 CFR 60.4211(f)(2). You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).
40 CFR 60.4209(a). Owners or operators of an emergency stationary CI internal combustion engine must install a non- resettable hour meter prior to startup of the engine.
40 CFR 60.4214(b). The owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation

during that time
Compliance Status:

___ In Compliance: Will you continue to comply up to permit issuance? ____Yes ____No

___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No

_X__ Future-Effective Requirement: Do you expect to meet this on a timely basis? _X_Yes _____No

Emission Unit ID(s):
FLNG2-FP1, FLNG2-FP2, FLNG2-FP3, FLNG2-FP4, FLNG2-FP5, FLNG2-FP6

Applicable Requirement (Description and Citation):
40 CFR 60.4205(c) and Table 4 to Subpart IIII of 40 CFR 60. Owners and operators of 2007 model year or later emergency CI ICE units must comply with the following emission standards based on the rated power of the unit:
Rated Power: kW > 560 kW (hp > 750 hp)

- NMHC+NOx: 6.4 g/kW-hr (4.8 g/hp-hr)
- CO: 3.5 g/kW-hr (2.6 g/hp-hr)
- PM: 0.20 g/kW-hr (0.15 g/hp-hr)

Compliance Methods for the Above (Description and Citation):
40 CFR 60.4211(c). Owners and operators must comply with this subpart by purchasing an engine certified to the emission standards in 40 CFR 60.4205(b) The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section.
40 CFR 60.4206. Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in 40 CFR 60.4205 over the entire life of the engine
40 CFR 60.4207(b). Owners and operators must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.
40 CFR 60.4211(a). Owner or operators must maintain the engines as follows: (1) operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions; (2) change only those emission-related settings that are permitted by the manufacturer; and (3) meet the requirements of 40 CFR part 1068, as they apply to you
40 CFR 60.4211(f). In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (3) of this section, is prohibited.
40 CFR 60.4211(f)(1). There is no time limit on the use of emergency stationary ICE in emergency situations.
40 CFR 60.4211(f)(2). You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).
40 CFR 60.4209(a). Owners or operators of an emergency stationary CI internal combustion engine must install a non- resettable hour meter prior to startup of the engine.
40 CFR 60.4214(b). The owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time
Compliance Status:

___ In Compliance: Will you continue to comply up to permit issuance? ____Yes ____No

___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No

_X__ Future-Effective Requirement: Do you expect to meet this on a timely basis? _X_Yes _____No

Emission Unit ID(s):
FLNG2-FP7, FLNG2-FP8

Applicable Requirement (Description and Citation):
40 CFR 60.4205(c) and Table 4 to Subpart IIII of 40 CFR 60. Owners and operators of 2007 model year or later emergency CI ICE units must comply with the following emission standards based on the rated power of the unit:
Rated Power: 225 ≤ KW <450

- NMHC+NOx: 4.0 g/kW-hr (3.0 g/hp-hr)
- CO: 3.5 g/kW-hr (2.6 g/hp-hr)
- PM: 0.20 g/kW-hr (0.15 g/hp-hr)

Compliance Methods for the Above (Description and Citation):
40 CFR 60.4211(c). Owners and operators must comply with this subpart by purchasing an engine certified to the emission standards in 40 CFR 60.4205(b) The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section.
40 CFR 60.4206. Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in 40 CFR 60.4205 over the entire life of the engine
40 CFR 60.4207(b). Owners and operators must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.
40 CFR 60.4211(a). Owner or operators must maintain the engines as follows: (1) operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions; (2) change only those emission-related settings that are permitted by the manufacturer; and (3) meet the requirements of 40 CFR part 1068, as they apply to you
40 CFR 60.4211(f). In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (3) of this section, is prohibited.
40 CFR 60.4211(f)(1). There is no time limit on the use of emergency stationary ICE in emergency situations.
40 CFR 60.4211(f)(2). You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).
40 CFR 60.4209(a). Owners or operators of an emergency stationary CI internal combustion engine must install a non- resettable hour meter prior to startup of the engine.
40 CFR 60.4214(b). The owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time
Compliance Status:

___ In Compliance: Will you continue to comply up to permit issuance? ____Yes ____No

___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No

_X__ Future-Effective Requirement: Do you expect to meet this on a timely basis? _X_Yes _____No

Emission Unit ID(s):
FLNG2-EDG1, FLNG2-EDG2, FLNG2-EDG3, FLNG2-EDG4, FLNG2-EDG5, FLNG2-EDG6, FLNG2-EDG7, FSU-EDG, FLNG2-FP1, FLNG2-FP2, FLNG2-FP3, FLNG2-FP4, FLNG2-FP5, FLNG2-FP6, FLNG2-FP7, FLNG2-FP8

Applicable Requirement (Description and Citation):
40 CFR 63.6590(c). An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part

Compliance Methods for the Above (Description and Citation):
40 CFR 63.6625(h). If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes

Compliance Status:

___ In Compliance: Will you continue to comply up to permit issuance? ____Yes ____No

___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No

_X__ Future-Effective Requirement: Do you expect to meet this on a timely basis? _X__Yes _____No

Emission Unit ID(s):
FSU-Boiler1, FSU-Boiler2

Applicable Requirement (Describe and Cite)
40 CFR 63.11210(g). Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler biennially as specified in § 63.11223

Compliance Methods for the Above (Description and Citation):
40 CFR 63.11225(b). Compliance certification report submitted biennially
40 CFR 63.11225(c). Records of notifications, reports and supporting documentation

Compliance Status:

___ In Compliance: Will you continue to comply up to permit issuance? ____Yes ____No

___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No

__X_ Future-Effective Requirement: Do you expect to meet this on a timely basis? _X_Yes ____No

Emission Unit ID(s):
FLNG1-TO, FLNG2-TO, FLNG1-CF, FLNG1-WF, FLNG2-CF, FLNG2-WF

Applicable Requirement (Describe and Cite)
40 CFR 64.3. Submit a Compliance Assurance Monitoring (CAM) Plan for the control of VOC emissions

Compliance Methods for the Above (Description and Citation):
40 CFR 64.7. Monitor in accordance with Approved CAM Plan
40 CFR 64.10(b). Keep records in accordance with Approved CAM Plan
40 CFR 64.10(a). Submit monitoring reports with Title V monitoring reports

Compliance Status:

___ In Compliance: Will you continue to comply up to permit issuance? ____Yes ____No

___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No

__X_ Future-Effective Requirement: Do you expect to meet this on a timely basis? _X_Yes ____No

B. SCHEDULE OF COMPLIANCE (NOT APPLICABLE)

Complete this section if you answered "NO" to any of the questions in section A. Also, complete this section if required to submit a schedule of compliance by an applicable requirement. Please attach copies of any judicial consent decrees or administrative orders for this requirement.

Unit(s)____________________ Requirement____

Reason for Noncompliance. Briefly explain reason for noncompliance at time of permit issuance or that future-effective requirement will not be met on a timely basis:

Narrative Description of how Source Compliance Will be Achieved. Briefly explain your plan for achieving compliance:

Schedule of Compliance. Provide a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance, including a date for final compliance.

Remedial Measure or Action	Date to be Achieved

C. SCHEDULE FOR SUBMISSION OF PROGRESS REPORTS (NOT APPLICABLE)

Only complete this section if you are required to submit one or more schedules of compliance in section B or if an applicable requirement requires submittal of a progress report. If a schedule of compliance is required, your progress report should start within 6 months of application submittal and subsequently, no less than every six months. One progress report may include information on multiple schedules of compliance.

Contents of Progress Report (describe):

First Report____/____/___ Frequency of Submittal_______________

Contents of Progress Report (describe):

First Report____/____/___ Frequency of Submittal_______________

D. SCHEDULE FOR SUBMISSION OF COMPLIANCE CERTIFICATIONS (NOT APPLICABLE)

This section must be completed once by every source. Indicate when you would prefer to submit compliance certifications during the term of your permit (at least once per year).

Frequency of submittal_______________________ Beginning____/____/____

E. COMPLIANCE WITH ENHANCED MONITORING & COMPLIANCE CERTIFICATION REQUIREMENTS (NOT APPLICABLE. FUTURE APPLICABLE REQUIREMENT.)

This section must be completed once by every source. To certify compliance with these, you must be able to certify compliance for every applicable requirement related to monitoring and compliance certification at every unit.

Enhanced Monitoring Requirements: ____ In Compliance ____ Not In Compliance

Compliance Certification Requirements: ____ In Compliance ____ Not In Compliance

ATTACHMENT B

LDEQ APPLICATION FOR APPROVAL OF EMISSIONS OF AIR POLLUTANTS FROM PART 70 SOURCES FORM

12. Proposed Project Emissions [LAC 33:III.517.D.3]

List the total emissions following the proposed project for this facility or process unit (for process unit-specific permits). Speciate all criteria pollutants, TAP, and HAP for the proposed project.

Pollutant	Proposed Emission Rate (tons/yr)
Nitrogen Oxides (NO_X)	673.5
Carbon Monoxide (CO)	669.3
Volatile Organic Compounds (VOCs)	41.0
Particulate Matter (PM)	82.9
PM_{10}	82.9
$PM_{2.5}$	82.9
Sulfur Dioxide (SO_2)	106.7
Carbon Dioxide (CO_2)	1,321,765
Greenhouse Gases as CO_2e (GHG)	1,332,401
Total Hazardous Air Pollutants (HAPs)	10.9
1,3-Butadiene	0.0038
Acetaldehyde	0.35
Acrolein	0.056
Benzene	0.12
Ethylbenzene	0.28
Formaldehyde	6.32
Naphthalene	0.012
Toluene	1.15
Xylenes	0.57
Sulfuric Acid	7.48

20. Insignificant Activities [LAC 33:III.501.B.5] - ☒ Yes ☐ No

Enter all activities that qualify as Insignificant Activities.

- Expand this table as necessary to include all such activities.
- For sources claimed to be insignificant based on size or emission rate (LAC 33:III.501.B.5.A), information must be supplied to verify each claim. This may include but is not limited to operating hours, volumes, and heat input ratings.
- If aggregate emissions from all similar pieces of equipment claimed to be insignificant are greater than 5 tons per year for any pollutant, then the activities can not be claimed as insignificant and must be represented as permitted emission sources. Aggregate emissions shall mean the total emissions from a particular insignificant activity or group of similar insignificant activities (e.g., A.1, A.2, etc.) within a permit per year.

Emission Point ID No.	Description	Physical/Operating Data	Citation
Pioneer 1 Fuel Oil Day Tank	1,210 gallon fuel oil tank	True vapor press. < 0.5 psia	LAC 33:111.501 B.5.A 3
Pioneer 1 Lube Oil Tank	1,235 gallon lube oil tank	True vapor press. < 0.5 psia	LAC 33:111.501 B.5.A 3
Pioneer 1 Lube Oil Purifier Tank	311 gallon lube oil tank	True vapor press. < 0.5 psia	LAC 33:111.501 B.5.A 3
Pioneer 1 Waste Oil Tank	9,828 gallon waste oil tank	True vapor press. < 0.5 psia	LAC 33:111.501 B.5.A 3
Pioneer 2 Fuel Oil Day Tank	4,754 gallon fuel oil tank	True vapor press. < 0.5 psia	LAC 33:111.501 B.5.A 3
Pioneer 2 Lube Oil Tank	1,428 gallon liube oil tank	True vapor press. < 0.5 psia	LAC 33:111.501 B.5.A 3
Pioneer 2 Waste Oil Tank	9,007 gallon waste oil tank	True vapor press. < 0.5 psia	LAC 33:111.501 B.5.A 3
Pioneer 4 Fuel Oil Day Tank	1,210 gallon fuel oil tank	True vapor press. < 0.5 psia	LAC 33:111.501 B.5.A 3
Pioneer 4 Lube Oil Tank	1,235 gallon lube oil tank	True vapor press. < 0.5 psia	LAC 33:111.501 B.5.A 3
Pioneer 4 Lube Oil Purifier Tank	311 gallon lube oil tank	True vapor press. < 0.5 psia	LAC 33:111.501 B.5.A 3
Pioneer 4 Waste Oil Tank	9,828 gallon waste oil tank	True vapor press. < 0.5 psia	LAC 33:111.501 B.5.A 3
Pioneer 5 Fuel Oil Day Tank	1,210 gallon fuel oil tank	True vapor press. < 0.5 psia	LAC 33:111.501 B.5.A 3
Pioneer 5 Lube Oil Tank	1,428 gallon lube oil tank	True vapor press. < 0.5 psia	LAC 33:111.501 B.5.A 3
Pioneer 5 Waste Oil Tank	9,007 gallon waste oil tank	True vapor press. < 0.5 psia	LAC 33:111.501 B.5.A 3
Pioneer 6 Day Tank Main	3,066 gallon fuel oil tank	True vapor press. < 0.5 psia	LAC 33:111.501 B.5.A 3
Pioneer 6 Day Tank Emergency	1,260 gallon fuel oil tank	True vapor press. < 0.5 psia	LAC 33:111.501 B.5.A 3
Pioneer 7 Fuel Oil Day Tank	1,210 gallon fuel oil tank	True vapor press. < 0.5 psia	LAC 33:111.501 B.5.A 3
Pioneer 7 Lube Oil Tank	1,235 gallon lube oil tank	True vapor press. < 0.5 psia	LAC 33:111.501 B.5.A 3
Pioneer 7 Lube Oil Purifier Tank	311 gallon lube oil tank	True vapor press. < 0.5 psia	LAC 33:111.501 B.5.A 3
Pioneer 7 Waste Oil Tank	9,828 gallon waste oil tank	True vapor press. < 0.5 psia	LAC 33:111.501 B.5.A 3
Pioneer 7 Day Tank Main	3,066 gallon fuel oil tank	True vapor press. < 0.5 psia	LAC 33:111.501 B.5.A 3
Pioneer 7 Day Tank Emergency	1,260 gallon fuel oil tank	True vapor press. < 0.5 psia	LAC 33:111.501 B.5.A 3
Pioneer 1 Fuel Oil Storage Tank #4P-1	90,216 gallon fuel oil tank	Emissions < 5 tpy	LAC 33:III.501.B.5.D
Pioneer 1 Fuel Oil Storage Tank #4S-1	45,234 gallon fuel oil tank	Emissions < 5 tpy	LAC 33:III.501.B.5.D
Pioneer 1 Fuel Oil Storage Tank #4S-2	44,940 gallon fuel oil tank	Emissions < 5 tpy	LAC 33:III.501.B.5.D
Pioneer 2 Fuel Oil Tank (1P)	23,302 gallon fuel oil tank	Emissions < 5 tpy	LAC 33:III.501.B.5.D
Pioneer 2 Fuel Oil Tank (1S)	43,193 gallon fuel oil tank	Emissions < 5 tpy	LAC 33:III.501.B.5.D
Pioneer 2 Fuel Oil Tank (2P)	31,412 gallon fuel oil tank	Emissions < 5 tpy	LAC 33:III.501.B.5.D
Pioneer 2 Fuel Oil Tank (2S)	31,412 gallon fuel oil tank	Emissions < 5 tpy	LAC 33:III.501.B.5.D
Pioneer 2 Fuel Oil Tank (3P)	52,781 gallon fuel oil tank	Emissions < 5 tpy	LAC 33:III.501.B.5.D
Pioneer 2 Non-Toxic Oil	76,453 gallon non-toxic oil tank	Emissions < 5 tpy	LAC 33:III.501.B.5.D
Pioneer 3 Diesel Fuel Tank 5P	49,455 gallon fuel oil tank	Emissions < 5 tpy	LAC 33:III.501.B.5.D

Emission Point ID No.	Description	Physical/Operating Data	Citation
Pioneer 3 Diesel Fuel Tank 5S	52,588 gallon fuel oil tank	Emissions < 5 tpy	LAC 33:III.501.B.5.D
Pioneer 3 Diesel Fuel Tank 7P	48,195 gallon fuel oil tank	Emissions < 5 tpy	LAC 33:III.501.B.5.D
Pioneer 3 Diesel Fuel Tank 7S	48,195 gallon fuel oil tank	Emissions < 5 tpy	LAC 33:III.501.B.5.D
Pioneer 3 Dirty Oil Tank 8C	10,189 gallon waste fuel oil tank	Emissions < 5 tpy	LAC 33:III.501.B.5.D
Pioneer 4 Fuel Oil Storage Tank #4P-1	90,216 gallon fuel oil tank	Emissions < 5 tpy	LAC 33:III.501.B.5.D
Pioneer 4 Fuel Oil Storage Tank #4S-1	45,234 gallon fuel oil tank	Emissions < 5 tpy	LAC 33:III.501.B.5.D
Pioneer 4 Fuel Oil Storage Tank #4S-2	44,940 gallon fuel oil tank	Emissions < 5 tpy	LAC 33:III.501.B.5.D
Pioneer 5 Fuel Oil Tank (1P)	23,302 gallon fuel oil tank	Emissions < 5 tpy	LAC 33:III.501.B.5.D
Pioneer 5 Fuel Oil Tank (1S)	43,193 gallon fuel oil tank	Emissions < 5 tpy	LAC 33:III.501.B.5.D
Pioneer 5 Fuel Oil Tank (2P)	31,412 gallon fuel oil tank	Emissions < 5 tpy	LAC 33:III.501.B.5.D
Pioneer 5 Fuel Oil Tank (2S)	31,412 gallon fuel oil tank	Emissions < 5 tpy	LAC 33:III.501.B.5.D
Pioneer 5 Fuel Oil Tank (3P)	52,781 gallon fuel oil tank	Emissions < 5 tpy	LAC 33:III.501.B.5.D
Pioneer 5 Non-Toxic Oil	76,453 gallon non-toxic oil tank	Emissions < 5 tpy	LAC 33:III.501.B.5.D
Pioneer 6 Diesel Fuel Tank 5P	49,455 gallon fuel oil tank	Emissions < 5 tpy	LAC 33:III.501.B.5.D
Pioneer 6 Diesel Fuel Tank 5S	52,588 gallon fuel oil tank	Emissions < 5 tpy	LAC 33:III.501.B.5.D
Pioneer 6 Diesel Fuel Tank 7P	48,195 gallon fuel oil tank	Emissions < 5 tpy	LAC 33:III.501.B.5.D
Pioneer 6 Diesel Fuel Tank 7S	48,195 gallon fuel oil tank	Emissions < 5 tpy	LAC 33:III.501.B.5.D
Pioneer 6 Dirty Oil Tank 8C	10,189 gallon waste fuel oil tank	Emissions < 5 tpy	LAC 33:III.501.B.5.D
Pioneer 7 Fuel Oil Storage Tank #4P-1	90,216 gallon fuel oil tank	Emissions < 5 tpy	LAC 33:III.501.B.5.D
Pioneer 7 Fuel Oil Storage Tank #4S-1	45,234 gallon fuel oil tank	Emissions < 5 tpy	LAC 33:III.501.B.5.D
Pioneer 7 Fuel Oil Storage Tank #4S-2	44,940 gallon fuel oil tank	Emissions < 5 tpy	LAC 33:III.501.B.5.D

22. Applicable Regulations, Air Pollution Control Measures, Monitoring, and Recordkeeping

Important points for Table 1 [LAC 33:III.517.D.10]:

- List in Table 1, by Emission Point ID Number and Descriptive Name of the Equipment, state and federal pollution abatement programs and note the applicability or non-applicability of the regulations to each source.
- Adjust the headings for the columns in Table 1 as necessary to reflect all applicable regulations, in addition to any regulations that do not apply but require an explanation to substantiate this fact.
- For each piece of equipment, enter "1" for each regulation that applies. Enter "2" for each regulation that applies to this type of source, but from which this source of emissions is exempt. Enter "3" for equipment that is subject to a regulation, but does not have any applicable requirements. Also, enter "3" for each regulation that has applicable requirements that apply to the particular emission source, but the regulations currently do not apply due to meeting a specific criterion, such as it has not been constructed, modified, or reconstructed since the regulations have been in place.
- Leave the spaces blank when the regulations clearly would not apply under any circumstances to the source. For example, LAC 33:III.2103 – Storage of Volatile Organic Compounds would never apply to a steam generating boiler, no matter the circumstances.
- Consult instructions.

Important points for Table 2 [LAC 33:III.517.D.4; LAC 33:III.517.D.7; LAC 33:III.517.D.10]:

- For each piece of equipment listed in Table 2, include all applicable limitations, recordkeeping, reporting, monitoring, and testing requirements. Also, include any one-time notification or one-time performance test requirements that have not been fulfilled.
- Each of these regulatory aspects (limitations, recordkeeping, reporting, etc.) should be addressed for each regulation that is applicable to each emissions source or emissions point.
- For each regulation that provides a choice regarding the method of compliance, indicate the method of compliance that will be employed. It is not sufficient to state that all compliance options will be employed, though multiple compliance options may be approved as alternative operating scenarios.
- Consult instructions.

Important points for Table 3 [LAC 33:III.517.D.16]:

- Each time a 2 or a 3 is used to describe applicability of a source in Table 1, an entry should be made in Table 3 that explains the exemption or non-applicability status of the regulation to that source.
- Fill in all requested information in the table.
- The exact regulatory citation that provides for the specific exemption or non-applicability determination should be entered into the "Citation Providing for Exemption or Non-applicability" column.
- Consult Instructions.

Important points for Table 4 [LAC 33:III.517.D.18]

- List any single emission source that routes its emissions to another point where these emissions are commingled with the emissions of other sources before being released to the atmosphere. Do not list any single emission source in this table that does not route its emissions in this manner.
- List any and all emission sources that are routed as described above. This includes emission sources that do not otherwise appear in this permit application.
- Consult instructions.

TABLE 1: APPLICABLE LOUISIANA AND FEDERAL AIR QUALITY REQUIREMENTS

Note: This table lists regulations that are commonly applicable to many sources, but is not intended to be an all inclusive list. Alter the headings of this table as necessary in order to address **ALL** potentially applicable requirements.

Source ID No.:	Descriptive Name of the Source	LAC 33:III							LAC 33:III.Chapter										
		509	2111	2113	2121	2103	2107	2108	5	9	11	13	29	51	56	59	15		
	Facility-Wide	1	2	1	3	2	2	2	1	1	1	1	1	3	1	3			
FLNG1 - CT	FLNG1 - Compressor Turbine										3	1					1		
FLNG2 – CT1	FLNG2 - Compressor Turbine										3	1					1		
FLNG1 - PGT1	FLNG1 - Power Generating Turbine #1										3	1					2		
FLNG1 – PGT2	FLNG1 - Power Generating Turbine #2										3	1					2		
FLNG1 – PGT3	FLNG1 - Power Generating Turbine #3										3	1					2		
FLNG2 - PGT1	FLNG2 - Power Generating Turbine #1										3	1					2		
FLNG2 – PGT2	FLNG2 - Power Generating Turbine #2										3	1					2		
FLNG2 – PGT3	FLNG2 - Power Generating Turbine #3										3	1					2		
FLNG1-TO	FLNG1 - Acid Gas Thermal Oxidizer																1		
FLNG2-TO	FLNG2 - Acid Gas Thermal Oxidizer																1		
FLNG1-CF	FLNG1 - Dry Flare										1						2		
FLNG1-WF	FLNG1 - Wet Flare										1						2		
FLNG2-CF	FLNG2 - Dry Flare										1						2		
FLNG2-WF	FLNG2 - Wet Flare										1						2		
FLNG1-EDG1	FLNG1 - Emergency Generator Engine #1										1	1					2		
FLNG1-EDG2	FLNG1 - Emergency Generator Engine #2										1	1					2		
FLNG1-EDG3	FLNG1 - Emergency Generator Engine #3										1	1					2		

TABLE 1: APPLICABLE LOUISIANA AND FEDERAL AIR QUALITY REQUIREMENTS

Note: This table lists regulations that are commonly applicable to many sources, but is not intended to be an all inclusive list. Alter the headings of this table as necessary in order to address **ALL** potentially applicable requirements.

Source	Descriptive Name of the Source	LAC 33:III							LAC 33:III.Chapter										
ID No.:		509	2111	2113	2121	2103	2107	2108	5	9	11	13	29	51	56	59	15		
FLNG1-EDG4	FLNG1 - Emergency Generator Engine #4										1	1					2		
FLNG1-EDG5	FLNG1 - Emergency Generator Engine #5										1	1					2		
FLNG1-EDG6	FLNG1 - Emergency Generator Engine #6										1	1					2		
FLNG1-EDG7	FLNG1 - Emergency Generator Engine #7										1	1					2		
FLNG2-EDG1	FLNG2 - Emergency Generator Engine #1										1	1					2		
FLNG2-EDG2	FLNG2 - Emergency Generator Engine #2										1	1					2		
FLNG2-EDG3	FLNG2 - Emergency Generator Engine #3										1	1					2		
FLNG2-EDG4	FLNG2 - Emergency Generator Engine #4										1	1					2		
FLNG2-EDG5	FLNG2 - Emergency Generator Engine #5										1	1					2		
FLNG2-EDG6	FLNG2 - Emergency Generator Engine #6										1	1					2		
FLNG2-EDG7	FLNG2 - Emergency Generator Engine #7										1	1					2		
FLNG2-FP1	FLNG2 - Emergency Fire Pump Engine #1										1	1					2		
FLNG2-FP2	FLNG2 - Emergency Fire Pump Engine #2										1	1					2		
FLNG2-FP3	FLNG2 - Emergency Fire Pump Engine #3										1	1					2		
FLNG2-FP4	FLNG2 - Emergency Fire Pump Engine #4										1	1					2		
FLNG2-FP5	FLNG2 - Emergency Fire Pump Engine #5										1	1					2		
FLNG2-FP6	FLNG2 - Emergency Fire Pump Engine #6										1	1					2		
FLNG2-FP7	FLNG2 - Emergency Fire Pump Engine #7										1	1					2		
FLNG2-FP8	FLNG2 - Emergency Fire Pump Engine #8										1	1					2		

TABLE 1: APPLICABLE LOUISIANA AND FEDERAL AIR QUALITY REQUIREMENTS

Note: This table lists regulations that are commonly applicable to many sources, but is not intended to be an all inclusive list. Alter the headings of this table as necessary in order to address **ALL** potentially applicable requirements.

Source ID No.:	Descriptive Name of the Source	LAC 33:III							LAC 33:III.Chapter										
		509	2111	2113	2121	2103	2107	2108	5	9	11	13	29	51	56	59	15		
FSU-EDG	FSU - Emergency Generator Engine										1	1					2		
FSU-Boiler1	FSU - Package Boiler #1										1	1					2		
FSU-Boiler2	FSU - Package Boiler #2										1	1					2		
FSU-GCU	FSU – Gas Combustion Unit										1	1					2		

KEY TO MATRIX

1 (Applicable) The regulations have applicable requirements that apply to this particular emissions source. This includes any monitoring, recordkeeping, or reporting requirements.
2 (Exempt) The regulations apply to this general type of emission source (i.e. vents, furnaces, towers, and fugitives) but do not apply to this particular emission source.
3 (Does Not Apply) The regulations do not apply to this emissions source. The regulations may have applicable requirements that could apply to this emissions source but the requirements do not currently apply to the source due to meeting a specific criterion, such as it has not been constructed, modified or reconstructed since the regulations have been in place.

Blank – The regulations clearly do not apply to this type of emission source.

TABLE 1: APPLICABLE LOUISIANA AND FEDERAL AIR QUALITY REQUIREMENTS

Note: This table lists regulations that are commonly applicable to many sources, but is not intended to be an all inclusive list. Alter the headings of this table as necessary in order to address **ALL** potentially applicable requirements.

Source ID No.:	Descriptive Name of the Source	40 CFR 60 NSPS							40 CFR 61			40 CFR 63						40 CFR	
		A	IIII	KKKK	Dc	OOOO			A			A	ZZZZ	JJJJJJ	YYYY	DDDDD		52	64
	Facility-Wide	1				2						1						1	
FLNG1 - CT	FLNG1 - Compressor Turbine	1		1											2				
FLNG2 – CT1	FLNG2 - Compressor Turbine #1	1		1											2				
FLNG1 - PGT1	FLNG1 - Power Generating Turbine #1	1		1											2				
FLNG1 – PGT2	FLNG1 - Power Generating Turbine #2	1		1											2				
FLNG1 – PGT3	FLNG1 - Power Generating Turbine #3	1		1											2				
FLNG2 - PGT1	FLNG2 - Power Generating Turbine #1	1		1											2				
FLNG2 – PGT2	FLNG2 - Power Generating Turbine #2	1		1											2				
FLNG2 – PGT3	FLNG2 - Power Generating Turbine #3	1		1											2				
FLNG1-EDG1	FLNG1 - Emergency Generator Engine #1	1										1	1						
FLNG1-EDG2	FLNG1 - Emergency Generator Engine #2	1										1	1						
FLNG1-EDG3	FLNG1 - Emergency Generator Engine #3	1										1	1						
FLNG1-EDG4	FLNG1 - Emergency Generator Engine #4	1										1	1						
FLNG1-EDG5	FLNG1 - Emergency Generator Engine #5	1										1	1						
FLNG1-EDG6	FLNG1 - Emergency Generator Engine #6	1										1	1						
FLNG1-EDG7	FLNG1 - Emergency Generator Engine #7	1										1	1						
FLNG2-EDG1	FLNG2 - Emergency Generator Engine #1	1	1									1	1						

TABLE 1: APPLICABLE LOUISIANA AND FEDERAL AIR QUALITY REQUIREMENTS

Note: This table lists regulations that are commonly applicable to many sources, but is not intended to be an all inclusive list. Alter the headings of this table as necessary in order to address **ALL** potentially applicable requirements.

Source ID No.:	Descriptive Name of the Source	40 CFR 60 NSPS							40 CFR 61			40 CFR 63						40 CFR	
		A	IIII	KKKK	Dc	OOOO			A			A	ZZZZ	JJJJJJ	YYYY	DDDDD		52	64
FLNG2-EDG2	FLNG2 - Emergency Generator Engine #2	1	1									1	1						
FLNG2-EDG3	FLNG2 - Emergency Generator Engine #3	1	1									1	1						
FLNG2-EDG4	FLNG2 - Emergency Generator Engine #4	1	1									1	1						
FLNG2-EDG5	FLNG2 - Emergency Generator Engine #5	1	1									1	1						
FLNG2-EDG6	FLNG2 - Emergency Generator Engine #6	1	1									1	1						
FLNG2-EDG7	FLNG2 - Emergency Generator Engine #7	1	1									1	1						
FLNG2-FP1	FLNG2 - Emergency Fire Pump Engine #1	1	1									1	1						
FLNG2-FP2	FLNG2 - Emergency Fire Pump Engine #2	1	1									1	1						
FLNG2-FP3	FLNG2 - Emergency Fire Pump Engine #3	1	1									1	1						
FLNG2-FP4	FLNG2 - Emergency Fire Pump Engine #4	1	1									1	1						
FLNG2-FP5	FLNG2 - Emergency Fire Pump Engine #5	1	1									1	1						
FLNG2-FP6	FLNG2 - Emergency Fire Pump Engine #6	1	1									1	1						
FLNG2-FP7	FLNG2 - Emergency Fire Pump Engine #7	1	1									1	1						
FLNG2-FP8	FLNG2 - Emergency Fire Pump Engine #8	1	1									1	1						
FSU-EDG	FSU - Emergency Generator Engine	1	1									1	1						
FLNG1-CF	FLNG1 - Dry Flare	1																	1
FLNG1-WF	FLNG1 - Wet Flare	1																	1

TABLE 1: APPLICABLE LOUISIANA AND FEDERAL AIR QUALITY REQUIREMENTS

Note: This table lists regulations that are commonly applicable to many sources, but is not intended to be an all inclusive list. Alter the headings of this table as necessary in order to address **ALL** potentially applicable requirements.

Source ID No.:	Descriptive Name of the Source	40 CFR 60 NSPS							40 CFR 61			40 CFR 63						40 CFR	
		A	IIII	KKKK	Dc	OOOO			A			A	ZZZZ	JJJJJJ	YYYY	DDDDD		52	64
FLNG2-CF	FLNG2 - Dry Flare	1																	1
FLNG2-WF	FLNG2 - Wet Flare	1																	1
FSU-Boiler1	FSU - Package Boiler #1				2							1		1		2			
FSU-Boiler2	FSU - Package Boiler #2				2							1		1		2			
FLNG1-TO	FLNG1 - Acid Gas Thermal Oxidizer																		1
FLNG2-TO	FLNG2 - Acid Gas Thermal Oxidizer																		1
FSU-GCU	FSU – Gas Combustion Unit																		

TABLE 1 CONTINUED

Source ID No.:	Descriptive Name of the Source	40 CFR 60 NSPS							40 CFR 61			40 CFR 63						40 CFR	
												H	Y	HH	HHH	SS		68	98
	Facility-Wide											2	2	2	2	2		2	1

KEY TO MATRIX

1 (Applicable) The regulations have applicable requirements that apply to this particular emissions source. This includes any monitoring, recordkeeping, or reporting requirements.
2 (Exempt) The regulations apply to this general type of emission source (i.e. vents, furnaces, towers, and fugitives) but do not apply to this particular emission source.
3 (Does Not Apply) The regulations do not apply to this emissions source. The regulations may have applicable requirements that could apply to this emissions source but the requirements do not currently apply to the source due to meeting a specific criterion, such as it has not been constructed, modified or reconstructed since the regulations have been in place.

Blank – The regulations clearly do not apply to this type of emission source.

TABLE 2: STATE AND FEDERAL AIR QUALITY REQUIREMENTS

For each Emission Point ID Number:

- List each regulation that applies.
- Arrange the requirements imposed by each regulation according to the headings provided below.
- Repeat this process for each regulation that applies to each source.
- State-only Requirements should be noted as such in the appropriate column.

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
Facility-Wide	LAC 33:III.Chapter 5	**Requirements that limit emissions or operations -**			
		Except as specified in LAC 33:III.Chapter 3, no construction, modification, or operation of a facility which ultimately may result in an initiation of, or an increase in, emission of air contaminants as defined in LAC 33:III.111 shall commence until the appropriate permit fee has been paid (in accordance with LAC 33:III.Chapter 2) and a permit (certificate of approval) has been issued by the permitting authority.	LAC 33:III.501.C.2	N/A	No
		The owner or operator of the source to which this Chapter applies shall have a general duty to operate under a permit, unless an exemption to the source applies or has been granted in accordance with this Chapter. The source shall be operated in accordance with all terms and conditions of the permit. Noncompliance with any term or condition of the permit shall constitute a violation of this Chapter and shall be grounds for enforcement action, for permit revision or termination, or for denial of a permit renewal application.	LAC 33:III.501.C.4	N/A	No
		The permitting authority shall incorporate into each permit sufficient terms and conditions to ensure compliance with all state and federally applicable air quality requirements and standards at the source and such other terms and conditions as determined by the permitting authority to be reasonable and necessary. It is the intent of this regulation that suitable controls be applied to new installations and relocations and in cases where modifications are to be made or where significant changes in emissions are anticipated.	LAC 33:III.501.C.6	N/A	No
		The Part 70 General Conditions listed in the table in LAC 33:III.535 apply to each Part 70 source as defined in LAC 33:III.502 upon issuance of the initial Part 70 permit for the source and shall continue to apply until such time as the Part 70 permit is terminated, rescinded, or replaced.	LAC 33:III.535	N/A	No
		The Louisiana general conditions listed in the table in LAC 33:III.537 apply to each source that requires an air permit according to LAC 33:III.501 upon issuance of the initial air permit for the source and shall continue to apply until such time as the permit is terminated or rescinded.	LAC 33:III.537	N/A	No
		Requirements that specify monitoring -			
		N/A	N/A	N/A	N/A

TABLE 2: STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
		Requirements that specify records to be kept and requirements that specify record retention time -			
		N/A	N/A	N/A	No
		Requirements that specify reports to be submitted -			
		Except as specified in LAC 33:III.Chapter 3, for each source to which this Chapter applies, the owner or operator shall submit a timely and complete permit application to the Office of Environmental Services as required in accordance with the procedures delineated herein. Permit applications shall be submitted prior to construction, reconstruction, or modification unless otherwise provided in this Chapter.	LAC 33:III.501.C.1	N/A	No
		Any permit application to renew an existing permit shall be submitted at least six months prior to the date of permit expiration, or at such earlier time as may be required by the existing permit or approved by the permitting authority. In no event shall the application for permit renewal be submitted more than 18 months before the date of permit expiration.	LAC 33:III.507.E.4	N/A	No
		Any permit application pertaining to a new or modified source shall be submitted prior to commencement of construction, reconstruction, or modification of the source. Construction, reconstruction, or modification of any source required to be permitted under this Chapter shall not commence prior to approval by the permitting authority.	LAC 33:III.517.A.1	N/A	No
		Any application form, report, or compliance certification submitted under this Chapter shall contain certification by a responsible official of truth, accuracy, and completeness. The certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information contained in the application are true, accurate, and complete.	LAC 33:III.517.B.1	N/A	No
		Duty to Supplement or Correct. Any applicant who fails to submit any relevant facts or who has submitted incorrect information in a permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information. In addition, an applicant shall provide additional information as necessary to address any requirements that become applicable to the source after the date it filed a complete application but prior to release of a proposed permit.	LAC 33:III.517.C	N/A	No
		Applications for permits shall be submitted in accordance with forms and guidance provided by the permitting authority.	LAC 33:III.517.D	N/A	No
		Each application pertaining to a Part 70 source shall include the elements specified with LAC 33:III.517.E.	LAC 33:III.517.E	N/A	No
		Requirements that specify performance testing -			
		N/A	N/A	N/A	N/A

TABLE 2: STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
Facility-Wide	LAC 33:III.509	**Requirements that limit emissions or operations -**			
		No new major stationary source or major modification to which the requirements of Subsection J- Paragraph R.5 of this Section apply shall begin actual construction without a permit that states that the major stationary source or major modification will meet those requirements.	LAC 33:III.509.A.3	N/A	No
		Requirements that specify monitoring -			
		N/A	N/A	N/A	N/A
		Requirements that specify records to be kept and requirements that specify record retention time -			
		N/A	N/A	N/A	N/A
		Requirements that specify reports to be submitted -			
		N/A	N/A	N/A	N/A
		Requirements that specify performance testing -			
		N/A	N/A	N/A	N/A
Facility-Wide	LAC 33:III.Chapter 9	**Requirements that limit emissions or operations -**			
		No person or group of persons shall allow particulate matter or gases to become airborne in amounts which cause the ambient air quality standards to be exceeded. The limits stated include normal background levels of particulates and gases.	LAC 33:III.929.A	N/A	No
		Requirements that specify monitoring -			
		N/A	N/A	N/A	N/A
		Requirements that specify records to be kept and requirements that specify record retention time -			
		N/A	N/A	N/A	N/A
		Requirements that specify reports to be submitted -			
		Both the emissions inventory and the certification statement required by Subparagraph F.1.c of this Section shall be submitted to the Office of Environmental Services by April 30 of each year (for the reporting period of the previous calendar	LAC 33:III.919.F.1.d	Annually	No

TABLE 2: STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
		year that coincides with period of ownership or operatorship), unless otherwise directed by the department. Any subsequent revisions shall be accompanied by a certification statement.			
		The unauthorized discharge of any air pollutant into the atmosphere shall be reported in accordance with the provisions of LAC 33:I.Chapter 39, Notification Regulations and Procedures for Unauthorized Discharges. Written reports pursuant to LAC 33:I.3925 must be submitted to the department. Timely and appropriate follow-up reports should be submitted detailing methods and procedures to be used to prevent similar atmospheric releases.	LAC 33:III.919.F.1.d	N/A	No
		Requirements that specify performance testing -			
		N/A	N/A	N/A	N/A
Facility-Wide	LAC 33:III.2113	**Requirements that limit emissions or operations -**			
		Best practical housekeeping and maintenance practices must be maintained at the highest possible standards to reduce the quantity of organic compounds emissions. Emission of organic compounds must be reduced wherever feasible. Good housekeeping shall include, but not be limited to, the following practices. 1. Spills of volatile organic compounds shall be avoided and clean up of such spills shall employ procedures that reduce or eliminate the emission of volatile organic compounds. 2. Containers of volatile organic compounds shall not be left open and the contents allowed to evaporate. 3. Waste materials that contain volatile organic compounds shall be stored and disposed of in a manner that reduces or eliminates the emission of volatile organic compounds. 4. Each facility shall develop a written plan for housekeeping and maintenance that places emphasis on the prevention or reduction of volatile organic compound emissions from the facility. This plan shall be submitted to the Office of Environmental Services upon request. A copy shall be kept at the facility, if practical, or at an alternate site approved by the department. 5. Good housekeeping shall be determined by compliance with LAC 33:III.2121 (Fugitive Emission Control) and the maintenance and the housekeeping plan required by LAC 33:III.2113.A.4.	LAC 33:III.2113.A	N/A	No
		Requirements that specify monitoring -			
		N/A	N/A	N/A	N/A
		Requirements that specify records to be kept and requirements that specify record retention time -			

TABLE 2: STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
		N/A	N/A	N/A	N/A
		Requirements that specify reports to be submitted -			
		N/A	N/A	N/A	N/A
		Requirements that specify performance testing -			
		N/A	N/A	N/A	N/A
Facility-Wide	LAC 33:III Chapter 29	**Requirements that limit emissions or operations -**			
		A person shall not discharge an odorous substance which causes a perceived odor intensity of six or greater on the specified eight point butanol scale when determined by the department's test method. (Method 41).	LAC 33:III.2901.D.	N/A	Yes
		Requirements that specify monitoring -			
		Requirements that specify records to be kept and requirements that specify record retention time -			
		N/A			
		Requirements that specify reports to be submitted -			
		Requirements that specify performance testing -			
		N/A			
Facility-Wide	LAC 33:III.Chapter 56	**Requirements that limit emissions or operations -**			
		When requested by the administrative authority, the persons responsible for the operation of this source shall submit a standby plan for the reduction or elimination of emissions during an air pollution alert, air pollution warning or air pollution emergency.	LAC 33:III.5611.A	N/A	No
		Requirements that specify monitoring -			
		N/A	N/A	N/A	N/A

TABLE 2: STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
		Requirements that specify records to be kept and requirements that specify record retention time -			
		N/A	N/A	N/A	N/A
		Requirements that specify reports to be submitted -			
		N/A	N/A	N/A	N/A
		Requirements that specify performance testing -			
		N/A	N/A	N/A	N/A
Facility-Wide	40 CFR 60 Subpart A	**Requirements that limit emissions or operations -**			
		The owner or operator will comply with applicable requirements to limit emissions or operations specified in 40 CFR 60 Subpart A for sources subject to a NSPS.	40 CFR 60.11 40 CFR 60.18	N/A	No
		Requirements that specify monitoring -			
		The owner or operator will comply with applicable requirements for monitoring specified in 40 CFR 60 Subpart A for sources subject to a NSPS	40 CFR 60.13	N/A	No
		Requirements that specify records to be kept and requirements that specify record retention time -			
		The owner or operator will comply with applicable requirements for recordkeeping and notification specified in 40 CFR 60 Subpart A for sources subject to a NSPS.	40 CFR 60.7	N/A	No
		Requirements that specify reports to be submitted -			
		The owner or operator will comply with applicable reporting requirements specified in 40 CFR 60 Subpart A for sources subject to a NSPS.	40 CFR 60.7 40 CFR 60.19	N/A	No
		Requirements that specify performance testing -			
		The owner or operator will comply with applicable performance testing requirements specified in 40 CFR 60 Subpart A for sources subject to a NSPS.	40 CFR 60.8	N/A	No
Facility-Wide	40 CFR 63 Subpart A	**Requirements that limit emissions or operations -**			
		The owner or operator will comply with applicable requirements to limit emissions or operations specified in 40 CFR 63 Subpart A for sources subject to a NSPS.	40 CFR 63.4 40 CFR 63.6	N/A	No

TABLE 2: STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
		Requirements that specify monitoring -			
		The owner or operator will comply with applicable requirements for monitoring specified in 40 CFR 63 Subpart A for sources subject to a NSPS	40 CFR 63.8	N/A	No
		Requirements that specify records to be kept and requirements that specify record retention time -			
		The owner or operator will comply with applicable requirements for recordkeeping and notification specified in 40 CFR 63 Subpart A for sources subject to a NSPS	40 CFR 63.10	N/A	No
		Requirements that specify reports to be submitted -			
		The owner or operator will comply with applicable reporting requirements specified in 40 CFR 63 Subpart A for sources subject to a NSPS	40 CFR 63.5 40 CFR 63.9 40 CFR 63.10	N/A	No
		Requirements that specify performance testing -			
		The owner or operator will comply with applicable performance testing requirements specified in 40 CFR 63 Subpart A for sources subject to a NSPS.	40 CFR 63.7	N/A	No
Facility-Wide	40 CFR 98 Subpart W	**Requirements that limit emissions or operations -**			
		N/A	N/A	N/A	N/A
		Requirements that specify monitoring -			
		The GHG emissions data for petroleum and natural gas emissions sources must be quality assured as applicable as specified in this section. Offshore petroleum and natural gas production facilities shall adhere to the monitoring and QA/QC requirements as set forth in 30 CFR 250.	40 CFR 98.234	N/A	No
		Requirements that specify records to be kept and requirements that specify record retention time -			
		For offshore petroleum and natural gas production, report CO2, CH4, and N2O emissions from equipment leaks, vented emission, and flare emission source types as identified in the data collection and emissions estimation study conducted by BOEMRE in compliance with 30 CFR 250.302 through 304. Offshore platforms do not need to report portable emissions. 40 CFR 98.3(g) Recordkeeping. An owner or operator that is required to report GHGs under this part must keep records as specified in this paragraph (g). Except as otherwise provided in this paragraph, retain all required records for at least 3 years from the date of submission of the annual GHG report for the reporting year in which the record was generated. The records shall be kept in an electronic or hard-copy	40 CFR 98.232(b) 40 CFR 98.233(s) 40 CFR 98.237 40 CFR 98.3	N/A	No

TABLE 2: STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
		format (as appropriate) and recorded in a form that is suitable for expeditious inspection and review. If the owner or operator of a facility is required under §98.5(b) to use verification software specified by the Administrator, then all records required for the facility under this part must be retained for at least 5 years from the date of submission of the annual GHG report for the reporting year in which the record was generated, starting with records for reporting year 2010. Upon request by the Administrator, the records required under this section must be made available to EPA. Records may be retained off site if the records are readily available for expeditious inspection and review. For records that are electronically generated or maintained, the equipment or software necessary to read the records shall be made available, or, if requested by EPA, electronic records shall be converted to paper documents. You must retain the following records, in addition to those records prescribed in each applicable subpart of this part: (1)-(7)			
		Requirements that specify reports to be submitted -			
		In addition to the information required by §98.3(c), each annual report must contain reported emissions and related information as specified in this section. Reporters that use a flow or volume measurement system that corrects to standard conditions as provided in the introductory text in §98.233 for data elements that are otherwise required to be determined at actual conditions, report gas volumes at standard conditions rather the gas volumes at actual conditions and report the standard temperature and pressure used by the measurement system rather than the actual temperature and pressure. (a) The annual report must include the information specified in paragraphs (a)(1) through (8) of this section for each applicable industry segment. The annual report must also include annual emissions totals, in metric tons of each GHG, for each applicable industry segment listed in paragraphs (a)(1) through (8) of this section, and each applicable emission source listed in paragraphs (b) through (z) of this section.	40 CFR 98.236 40 CFR 98.3	N/A	No
		Requirements that specify performance testing -			
		N/A	N/A	N/A	N/A
FLNG1 – CT, FLNG2 – CT1, FLNG1 - PGT1, FLNG1 – PGT2, FLNG1 – PGT3, FLNG2 - PGT1, FLNG2 – PGT2,	LAC 33:III.Chapter 13	**Requirements that limit emissions or operations -**			
		Limitations. No person shall cause, suffer, allow or permit the emission of particulate matter to the atmosphere from any fuel burning equipment in excess of 0.6 pounds per 10^6 Btu of heat input.	LAC 33:III.1313.C	N/A	No
		Requirements that specify monitoring -			
		N/A	N/A	N/A	N/A

TABLE 2: STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
FLNG2 – PGT3, FLNG1 – TO, FLNG2 – TO, FLNG1-EDG1, FLNG1-EDG2, FLNG1-EDG3, FLNG1-EDG4, FLNG1-EDG5, FLNG1-EDG6, FLNG1-EDG7, FLNG2-EDG1, FLNG2-EDG2, FLNG2-EDG3, FLNG2-EDG4, FLNG2-EDG5, FLNG2-EDG6, FLNG2-EDG7, FLNG2-FP1, FLNG2-FP2, FLNG2-FP3, FLNG2-FP4, FLNG2-FP5, FLNG2-FP6, FLNG2-FP7, FLNG2-FP8, FSU-Boiler1, FSU-Boiler2, FSU-EDG, FSU-GCU		**Requirements that specify records to be kept and requirements that specify record retention time -**			
		N/A	N/A	N/A	N/A
		Requirements that specify reports to be submitted -			
		N/A	N/A	N/A	N/A
		Requirements that specify performance testing -			
		N/A	N/A	N/A	N/A
FLNG1 – CT, FLNG2 – CT1	LAC 33:III.Chapter 15	**Requirements that limit emissions or operations -**			
		Limitations. Discharge gases shall not exceed a concentration of SO2 in excess of 2,000 parts per million (ppm) by volume at standard conditions (three hour average), or any applicable Federal NSPS or NESHAP emission limitation, whichever is more stringent. Single point sources that emit or have the potential to emit less than 250 tons per year of	LAC 33:III.1503.C	N/A	No

TABLE 2: STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
		sulfur compounds measured as sulfur dioxide may be exempted from the 2,000 ppm(v) limitation by the administrative authority.			
		Requirements that specify monitoring -			
		N/A. NSPS Subpart KKKK is more stringent. Exempt from fuel sulfur monitoring	40 CFR 60.4365	N/A	N/A
		Requirements that specify records to be kept and requirements that specify record retention time -			
		N/A	N/A	N/A	N/A
		Requirements that specify reports to be submitted -			
		N/A	N/A	N/A	N/A
		Requirements that specify performance testing -			
		N/A	N/A	N/A	N/A
FLNG1 – TO FLNG2 – TO	LAC 33:III.Chapter 15	**Requirements that limit emissions or operations -**			
		Limitations. Discharge gases shall not exceed a concentration of SO2 in excess of 2,000 parts per million (ppm) by volume at standard conditions (three hour average), or any applicable Federal NSPS or NESHAP emission limitation, whichever is more stringent. Single point sources that emit or have the potential to emit less than 250 tons per year of sulfur compounds measured as sulfur dioxide may be exempted from the 2,000 ppm(v) limitation by the administrative authority.	LAC 33:III.1503.C	N/A	No
		Requirements that specify monitoring -			
		NA.	LAC 33:III.1511.D.2	N/A	N/A
		Requirements that specify records to be kept and requirements that specify record retention time -			
		Initial compliance	LAC 33:III.1513.A.2	N/A	N/A
		Requirements that specify reports to be submitted -			

TABLE 2: STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
		Initial compliance report shall be submitted no later than 90 days after the completion of the test.	LAC 33:III.1513.A.2	N/A	N/A
		Requirements that specify performance testing -			
		Initial compliance	LAC 33:III.1503.D	N/A	N/A
FLNG1 – CT, FLNG2 – CT1, FLNG1 - PGT1, FLNG1 – PGT2, FLNG1 – PGT3, FLNG2 - PGT1, FLNG2 – PGT2, FLNG2 – PGT3	40 CFR 60 Subpart KKKK	**Requirements that limit emissions or operations -**			
		The turbine must meet a NOx limit of 25 ppm at 15 percent O2 or 150 ng/J of useful output (1.2 lb/MWh)	40 CFR 60.4320(a) and Table 1 to Subpart KKKK of Part 60	Hourly average	No
		The owner or operator must comply with either of these conditions: (2) the turbine must not burn fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input.	40 CFR 60.4330(a)(2)	N/A	No
		The owner or operator must operate and maintain the stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.	40 CFR 60.4333	N/A	No
		Requirements that specify monitoring -			
		For any lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NOX mode The owner or operator must monitor the total sulfur content of the fuel being fired in the turbine. The sulfur content of the fuel must be determined using total sulfur methods described in 40 CFR 60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377, which measure the major sulfur compounds, may be used. You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO2/J (0.060 lb SO2/MMBtu) heat input if representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO2/J (0.060 lb SO2/MMBtu) heat input for continental areas	40 CFR 60.4340(b)(2)(ii) 40 CFR 60.4360 40 CFR 60.4365(b) 40 CFR 60.4370(b) and (c)	N/A	No

TABLE 2: STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
		If you elect not to demonstrate sulfur content using options in § 60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day. Notwithstanding the requirements of paragraph 40 CFR 60.4370 (b), operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply.			
		Requirements that specify records to be kept and requirements that specify record retention time -			
		Records of fuel sulfur content	40 CFR 60.4360 40 CFR 60.4365 40 CFR 60.4370	N/A	No
		Requirements that specify reports to be submitted -			
		For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, the owner or operator must submit reports of excess emissions and monitor downtime, in accordance with § 60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction	40 CFR 60.4375(a)	Semi-annually	No
		All reports required under 40 CFR 60 7(c) must be postmarked by the 30th day following the end of each 6-month period	40 CFR 60.4375	Semi-annually	No
		Requirements that specify performance testing -			
		The owner or operator must perform performance tests of each turbine in accordance with § 60.4400 to demonstrate continuous compliance unless an alternative continuous compliance method is selected per 40 CFR 60.4400. If the NO_x emission result from the performance test is less than or equal to 75 percent of the NO_x emission limit for the turbine, the frequency of subsequent performance tests may be reduced to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the NO_x emission limit for the turbine, annual performance tests must be resumed. As an alternative, the owner or operator may install, calibrate, maintain and operate one of the following continuous monitoring systems: (1) Continuous emission monitoring as described in 40 60.4335(b) and 40 CFR 60.4345, or (2) Continuous parameter monitoring as follows: For a lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NOX mode.	40 CFR 60.4340(a)	Annual	No

TABLE 2: STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
		You must conduct an initial performance test, as required in § 60.8. Subsequent NOx performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).	40 CFR 60.4400	N/A	No
FLNG1-TO, FLNG2-TO, FLNG1-EDG1, FLNG1-EDG2, FLNG1-EDG3, FLNG1-EDG4, FLNG1-EDG5, FLNG1-EDG6, FLNG1-EDG7, FLNG2-EDG1, FLNG2-EDG2, FLNG2-EDG3, FLNG2-EDG4, FLNG2-EDG5, FLNG2-EDG6, FLNG2-EDG7, FLNG2-FP1, FLNG2-FP2, FLNG2-FP3, FLNG2-FP4, FLNG2-FP5, FLNG2-FP6, FLNG2-FP7, FLNG2-FP8, FSU-EDG, FSU-Boiler1, FSU-Boiler2, FSU-GCU	LAC 33:III. Chapter 11	**Requirements that limit emissions or operations -**			
		Control of Smoke. Except as specified in LAC 33:III.1105, the emission of smoke generated by the burning of fuel or combustion of waste material in a combustion unit, including the incineration of industrial, commercial, institutional and municipal wastes, shall be controlled so that the shade or appearance of the emission is not darker than 20 percent average opacity, except that such emissions may have an average opacity in excess of 20 percent for not more than one six minute period in any 60 consecutive minutes..	LAC 33:III.1101.A	N/A	No
		Requirements that specify monitoring -			
		N/A	N/A	N/A	N/A
		Requirements that specify records to be kept and requirements that specify record retention time -			
		N/A	N/A	N/A	N/A
		Requirements that specify reports to be submitted -			
		N/A	N/A	N/A	N/A
		Requirements that specify performance testing -			
		N/A	N/A	N/A	N/A
FLNG1-CF, FLNG1-WF,	LAC 33:III. Chapter 11	**Requirements that limit emissions or operations -**			
		The emission of smoke from a flare or other similar device used for burning in connection with pressure valve releases for control over process upsets shall be controlled so that the shade or appearance of the emission does not exceed 20 percent	LAC 33:III.1105.A	N/A	No

TABLE 2: STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
FLNG2-CF, FLNG2-WF		opacity (LAC 33:III.1503.D.2, Table 4) for a combined total of 6 hours in any 10 consecutive days. If it appears the emergency cannot be controlled in six hours, SPOC shall be notified by the emitter in accordance with LAC 33:I.3923 as soon as possible after the start of the upset period. Such notification does not imply the administrative authority will automatically grant an exemption to the source(s) of excessive emissions.			
		Exemptions from the provisions of LAC 33:III.1105.A may be granted by the administrative authority during startup and shutdown periods if the flaring was not the result of failure to maintain or repair equipment. A report in writing, explaining the conditions and duration of the start-up or shutdown and listing the steps necessary to remedy, prevent, and limit the excess emission, shall be submitted to SPOC within seven calendar days of the occurrence. In addition, the flaring must be minimized and no ambient air quality standard may be jeopardized.	LAC 33:III.1107.A	N/A	No
		Requirements that specify monitoring -			
		N/A	N/A	N/A	N/A
		Requirements that specify records to be kept and requirements that specify record retention time -			
		N/A	N/A	N/A	N/A
		Requirements that specify reports to be submitted -			
		N/A	N/A	N/A	N/A
		Requirements that specify performance testing -			
		N/A	N/A	N/A	N/A
FLNG2-EDG1, FLNG2-EDG2, FLNG2-EDG3, FLNG2-EDG4, FLNG2-EDG5, FLNG2-EDG6, FLNG2-EDG7, FSU-EDG	40 CFR 60 Subpart IIII	**Requirements that limit emissions or operations -**			
		Owners and operators of 2007 model year or later emergency CI ICE units must comply with the following emission standards based on the rated power of the unit: Rated Power: kW > 560 kW (hp > 750 hp) • NMHC+NOx: 6.4 g/kW-hr (4.8 g/hp-hr) • CO: 3.5 g/kW-hr (2.6 g/hp-hr) • PM: 0.20 g/kW-hr (0.15 g/hp-hr)	40 CFR 60.4205(b) Table 3 to Subpart IIII of 40 CFR 60	N/A	No
		Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in 40 CFR 60.4205 over the entire life of the engine.	40 CFR 60.4206	N/A	No

TABLE 2: STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
		Owners and operators must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.	40 CFR 60.4207(b)	N/A	No
		Owner or operators must maintain the engines as follows: (1) operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions; (2) change only those emission-related settings that are permitted by the manufacturer; and (3) meet the requirements of 40 CFR part 1068, as they apply to you.	40 CFR 60.4211(a)	N/A	No
		Owners and operators must comply with this subpart by purchasing an engine certified to the emission standards in 40 CFR 60.4205(b) The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section.	40 CFR 60.4211(c)	N/A	No
		In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (3) of this section, is prohibited.	40 CFR 60.4211(f)	N/A	No
		There is no time limit on the use of emergency stationary ICE in emergency situations.	40 CFR 60.4211(f)(1)	N/A	No
		You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).	40 CFR 60.4211(f)(2)	N/A	No
		Requirements that specify monitoring -			
		Owners or operators of an emergency stationary CI internal combustion engine must install a non- resettable hour meter prior to startup of the engine.	40 CFR 60.4209(a)	N/A	No
		The owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time	40 CFR 60.4214(b)	N/A	No
		Requirements that specify records to be kept and requirements that specify record retention time -			
		N/A	N/A	N/A	N/A
		Requirements that specify reports to be submitted -			
		N/A	N/A	N/A	N/A
		Requirements that specify performance testing -			
		N/A	N/A	N/A	N/A

TABLE 2: STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
FLNG2-FP1, FLNG2-FP2, FLNG2-FP3, FLNG2-FP4, FLNG2-FP5, FLNG2-FP6	40 CFR 60 Subpart IIII	**Requirements that limit emissions or operations -**			
		Owners and operators of 2007 model year or later emergency CI ICE fire pump engines must comply with the following emission standards based on the rated power of the unit: Rated Power: kW > 560 kW (hp > 750 hp) • NMHC+NOx: 6.4 g/kW-hr (4.8 g/hp-hr) • CO: 3.5 g/kW-hr (2.6 g/hp-hr) • PM: 0.20 g/kW-hr (0.15 g/hp-hr)	40 CFR 60.4205(c) Table 4 to Subpart IIII of 40 CFR 60	N/A	No
		Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in 40 CFR 60.4205 over the entire life of the engine.	40 CFR 60.4206	N/A	No
		Owners and operators must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.	40 CFR 60.4207(b)	N/A	No
		Owner or operators must maintain the engines as follows: (1) operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions; (2) change only those emission-related settings that are permitted by the manufacturer; and (3) meet the requirements of 40 CFR part 1068, as they apply to you..	40 CFR 60.4211(a)	N/A	No
		Owners and operators must comply with this subpart by purchasing an engine certified to the emission standards in 40 CFR 60.4205(b) The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section.	40 CFR 60.4211(c)	N/A	No
		In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (3) of this section, is prohibited.	40 CFR 60.4211(f)	N/A	No
		There is no time limit on the use of emergency stationary ICE in emergency situations.	40 CFR 60.4211(f)(1)	N/A	No
		You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).	40 CFR 60.4211(f)(2)	N/A	No
		Requirements that specify monitoring -			
		Owners or operators of an emergency stationary CI internal combustion engine must install a non- resettable hour meter prior to startup of the engine.	40 CFR 60.4209(a)	N/A	No
		The owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time	40 CFR 60.4214(b)	N/A	No

TABLE 2: STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
		Requirements that specify records to be kept and requirements that specify record retention time -			
		N/A	N/A	N/A	N/A
		Requirements that specify reports to be submitted -			
		N/A	N/A	N/A	N/A
		Requirements that specify performance testing -			
		N/A	N/A	N/A	N/A
FLNG2-FP7, FLNG2-FP8	40 CFR 60 Subpart IIII	**Requirements that limit emissions or operations -**			
		Owners and operators of 2007 model year or later emergency CI ICE fire pump engines must comply with the following emission standards based on the rated power of the unit: Rated Power: 225≤KW <450 • NMHC+NOx: 4.0 g/kW-hr (3.0 g/hp-hr) • CO: 3.5 g/kW-hr (2.6 g/hp-hr) • PM: 0.20 g/kW-hr (0.15 g/hp-hr)	40 CFR 60.4205(c) Table 4 to Subpart IIII of 40 CFR 60	N/A	No
		Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in 40 CFR 60.4205 over the entire life of the engine.	40 CFR 60.4206	N/A	No
		Owners and operators must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.	40 CFR 60.4207(b)	N/A	No
		Owner or operators must maintain the engines as follows: (1) operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions; (2) change only those emission-related settings that are permitted by the manufacturer; and (3) meet the requirements of 40 CFR part 1068, as they apply to you..	40 CFR 60.4211(a)	N/A	No
		Owners and operators must comply with this subpart by purchasing an engine certified to the emission standards in 40 CFR 60.4205(b) The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section.	40 CFR 60.4211(c)	N/A	No
		In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (3) of this section, is prohibited.	40 CFR 60.4211(f)	N/A	No
		There is no time limit on the use of emergency stationary ICE in emergency situations.	40 CFR 60.4211(f)(1)	N/A	No

TABLE 2: STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
		You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).	40 CFR 60.4211(f)(2)	N/A	No
		Requirements that specify monitoring -			
		Owners or operators of an emergency stationary CI internal combustion engine must install a non- resettable hour meter prior to startup of the engine.	40 CFR 60.4209(a)	N/A	No
		The owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time	40 CFR 60.4214(b)	N/A	No
		Requirements that specify records to be kept and requirements that specify record retention time -			
		N/A	N/A	N/A	N/A
		Requirements that specify reports to be submitted -			
		N/A	N/A	N/A	N/A
		Requirements that specify performance testing -			
		N/A	N/A	N/A	N/A
FLNG1-EDG1, FLNG1-EDG2, FLNG1-EDG3, FLNG1-EDG4, FLNG1-EDG5, FLNG1-EDG6, FLNG1-EDG7	40 CFR 63 Subpart ZZZZ	**Requirements that limit emissions or operations -**			
		Comply with the requirements in Table 2d to this subpart. a. Change oil and filter every 500 hours of operation or annually, whichever comes first; b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	40 CFR 63.6603(a) and 63.6640(a):	N/A	No
		Use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel	40 CFR 63.6604(b):	N/A	No
		At all times you must operate and maintain the engine, including associated monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may	40 CFR 63.6605(b):	N/A	No

TABLE 2: STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
		include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.			
		You must be in compliance with the operating limitations in this subpart that apply to you at all times.	40 CFR 63.6605(a):	N/A	No
		Operate and maintain the engine according to the manufacturer's written instructions or develop your own maintenance plan which must provide, to the extent practicable, for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.	40 CFR 63.6625(e):	N/A	No
		Minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to this subpart apply.	40 CFR 63.6625(h):	N/A	No
		You have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Table 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content.	40 CFR 63.6625(i):	N/A	No
		If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1) through (4) of this section. In order for the engine to be considered an emergency stationary RICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in nonemergency situations for 50 hours per year, as described in paragraphs (f)(1) through (4) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (4) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non- emergency engines. (1) There is no time limit on the use of emergency stationary RICE in emergency situations. (2) You may operate your emergency stationary RICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2). (i) Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require	40 CFR 63.6640(f):	N/A	No

TABLE 2: STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
		maintenance and testing of emergency RICE beyond 100 hours per calendar year. (3) Emergency stationary RICE located at major sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity. (4) Emergency stationary RICE located at area sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraphs (f)(4)(i) and (ii) of this section, the 50 hours per year for nonemergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity. (i) Prior to May 3, 2014, the 50 hours per year for non-emergency situations can be used for peak shaving or nonemergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engine is operated as part of a peak shaving (load management program) with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system. (ii) The 50 hours per year for nonemergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met: (A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator. (B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region. (C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines. (D) The power is provided only to the facility itself or to support the local transmission and distribution system.			

TABLE 2: STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
		(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.			
		Requirements that specify monitoring -			
		Install a non-resettable hour meter	40 CFR 63.6625(f):	N/A	No
		Requirements that specify records to be kept and requirements that specify record retention time -			
		N/A	N/A	N/A	N/A
		You must keep the records described in paragraphs (a)(2), (a)(4) and (a)(5) of this section. (2) Records of the occurrence and duration of each malfunction of operation (i.e., process equipment) or the air pollution control and monitoring equipment. (4) Records of all required maintenance performed on the monitoring equipment. (5) Records of actions taken during periods of malfunction to minimize emissions in accordance with §63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.	40 CFR 63.6655(a):	N/A	No
		You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE according to your own maintenance plan, as applicable.	40 CFR 63.6655(e)(2)	N/A	No
		You must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engine is used for the purposes specified in § 63.6640(f)(2)(ii) or (iii) or § 63.6640(f)(4)(ii), the owner or operator must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation for these purposes.	40 CFR 63.6655(f)(2):	N/A	No
		Requirements that specify reports to be submitted -			

TABLE 2: STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
		N/A	N/A	N/A	N/A
		Requirements that specify performance testing -			
		N/A	N/A	N/A	N/A
FLNG2-EDG1, FLNG2-EDG2, FLNG2-EDG3, FLNG2-EDG4, FLNG2-EDG5, FLNG2-EDG6, FLNG2-EDG7, FLNG2-FP1, FLNG2-FP2, FLNG2-FP3, FLNG2-FP4, FLNG2-FP5, FLNG2-FP6, FLNG2-FP7, FLNG2-FP8, FSU-EDG	40 CFR 63 Subpart ZZZZ	**Requirements that limit emissions or operations -**			
		An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.	40 CFR 63.6590(c)	N/A	No
		If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes.	40 CFR 63.6625(h)		
		Requirements that specify monitoring -			
		N/A	N/A	N/A	N/A
		Requirements that specify records to be kept and requirements that specify record retention time -			
		N/A	N/A	N/A	N/A
		Requirements that specify reports to be submitted -			
		N/A	N/A	N/A	N/A
		Requirements that specify performance testing -			
		N/A	N/A	N/A	N/A
FSU-Boiler1, FSU-Boiler2	40 CFR 63 Subpart JJJJJJ	**Requirements that limit emissions or operations -**			
		Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler biennially as specified in § 63.11223.	40 CFR 63.11210(g)	N/A	No
				N/A	No
		Requirements that specify monitoring -			
		N/A	N/A	N/A	N/A

TABLE 2: STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
		Requirements that specify records to be kept and requirements that specify record retention time -			
		Records of notifications, reports and supporting documentation	40 CFR 63.11225(c)	N/A	N/A
		Requirements that specify reports to be submitted -			
		Compliance certification report	40 CFR 63.11225(b)	March 1st biennially	N/A
		Requirements that specify performance testing -			
		N/A	N/A	N/A	N/A
FLNG1-TO, FLNG2-TO, FLNG1-CF, FLNG1-WF, FLNG2-CF, FLNG2-WF	40 CFR 64	**Requirements that limit emissions or operations -**			
		Submit a Compliance Assurance Monitoring (CAM) Plan for the control of VOC emissions	40 CFR 64.3	N/A	No
		Requirements that specify monitoring -			
		Monitor in accordance with Approved CAM Plan	40 CFR 64.7	N/A	N/A
		Requirements that specify records to be kept and requirements that specify record retention time -			
		Keep records in accordance with Approved CAM Plan	40 CFR 64.10(b)	N/A	N/A
		Requirements that specify reports to be submitted -			
		Submit monitoring reports with Title V monitoring reports	40 CFR 64.10(a)	Every 6 months	N/A
		Requirements that specify performance testing -			
		N/A	N/A	N/A	N/A

TABLE 3: EXPLANATION FOR EXEMPTION STATUS OR NON-APPLICABILITY OF A SOURCE

Emission Point ID No:	Requirement	Exempt or Does Not Apply	Explanation	Citation Providing for Exemption or Non-applicability
Facility-Wide	40 CFR 68	Does not apply	LNG facilities are subject to U.S. Department of Transportation safety regulations (e.g., 49 CFR § 193 and 33 CFR § 127). Pursuant to the definition of stationary source under 40 CFR § 68.3, transportation sources subject to 49 CFR § 193 are not stationary sources and therefore 40 CFR § 68 does not apply to the Project.	40 CFR 68.3 and 40 CFR 68.10a
	40 CFR 60 Subpart OOOO	Does not apply	Onshore facilities are defined under 40 CFR § 60.5430 as those that are located in the territorial seas or on the OCS. The Project is not located in territorial seas or the OCS and therefore will not be subject to Subpart OOOO.	40 CFR § 60.5430
	40 CFR 60 Subpart OOOOa	Does not apply	Onshore facilities are defined under 40 CFR § 60.5430a as those that are located in the territorial seas or on the OCS. The Project is not located in territorial seas or the OCS and therefore will not be subject to Subpart OOOO.	40 CFR § 60.5430a
	40 CFR 61 Subpart V	Does not apply	The LNG to be handled and loaded at the DWP will contain a very small amount of benzene estimated at no greater than 1 ppmv, which is far below 10 percent by weight. Therefore, 40 CFR Part 61 Subpart V does not apply to the Project	40 CFR §61.245(d)
	LAC 33.III.2103	Does not apply	The Project's diesel and fuel oil storage tanks will have a true vapor less than 1.5 psia. The Project's LNG storage tanks will have a true vapor less than 1.5 psia at storage temperature (approximately -260°F).	LAC 33.III.2103 B
	LAC 33.III.2107	Does not apply	The Project's LNG loading operations will have a true vapor pressure of VOCs less than 1.5 psia.	LAC 33.III.2107 A
	LAC 33.III.2108	Does not apply	The Project's LNG loading operations will have a true vapor pressure of VOCs less than 1.5 psia.	LAC 33.III.2108 A
	LAC 33.III.2111	Does not apply	The Project's pumps and compressors will have a true vapor pressure of VOCs less than 1.5 psia.	LAC 33.III.2111 A
	LAC 33.III.2121	Does not apply	Facility is not an affected natural gas processing plant as defined	LAC 33.III.2121 A
	40 CFR 63 Subpart H	Does not apply	Project will not include any equipment that contains or contacts a fluid (liquid or gas) that is at least 5 percent by weight of total organic HAPs, on an annual average basis and therefore is exempt from NESHAP Subpart H.	40 CFR § 63.161
	40 CFR 63 Subpart HH	Does not apply	Project is not considered an oil and natural gas production, as it does not process, upgrade, or store natural gas prior to the point at which natural gas enters the	40 CFR § 63.760(a)(3)

TABLE 3: EXPLANATION FOR EXEMPTION STATUS OR NON-APPLICABILITY OF A SOURCE

Emission Point ID No:	Requirement	Exempt or Does Not Apply	Explanation	Citation Providing for Exemption or Non-applicability
			natural gas transmission and storage source category or is delivered to a final end user.	
	40 CFR 63 Subpart HHH	Does not apply	Project's natural gas will not be delivered to a pipeline or to a final end user	40 CFR § 63.1270
	40 CFR 63 Subpart Y	Exempt	Subpart Y exempts marine tank vessel loading that only transfers liquids containing organic HAP as impurities. The HAP compounds present in LNG meet the criteria of impurities	40 CFR §63.561
	40 CFR 63 Subpart SS	Does not apply	Applies when another subpart references the use of this subpart for such air emission control. The Project's emission sources are not subject to another subpart that references 40 CFR 63 Subpart SS.	40 CFR §63.980
	LAC 33:111. Chapter 51	Exempt	The Project is not a major source as defined in LAC 33:III.5103	33.III.5101.A
	LAC 33:111. Chapter 59	Does Not Apply	Pursuant to 40 CFR 68.3, stationary sources do not include transportation sources subject to 49 CFR Parts 193 ad the Project will be subject to 49 C'FR Part 193 and therefore, 40 CFR Part 68 does not apply.	40 CFR 68.3
FLNG1 - PGT1, FLNG1 – PGT2, FLNG1 – PGT3, FLNG2 - PGT1, FLNG2 – PGT2, FLNG2 – PGT3, FLNG1-CF, FLNG1-WF, FLNG2-CF, FLNG2-WF, FLNG1-EDG1, FLNG1-EDG2, FLNG1-EDG3, FLNG1-EDG4, FLNG1-EDG5, FLNG1-EDG6, FLNG1-EDG7,	LAC 33.III Chapter 15	Exempt	Individual source potential to emit SO_2 less than 5 tpy	LAC 33.III 1502 A.3

TABLE 3: EXPLANATION FOR EXEMPTION STATUS OR NON-APPLICABILITY OF A SOURCE

Emission Point ID No:	Requirement	Exempt or Does Not Apply	Explanation	Citation Providing for Exemption or Non-applicability
FLNG2-EDG1, FLNG2-EDG2, FLNG2-EDG3, FLNG2-EDG4, FLNG2-EDG5, FLNG2-EDG6, FLNG2-EDG7, FLNG2-FP1, FLNG2-FP2, FLNG2-FP3, FLNG2-FP4, FLNG2-FP5, FLNG2-FP6, FLNG2-FP7, FLNG2-FP8, FSU-EDG, FSU-Boiler1, FSU-Boiler2, FSU-GCU				
FLNG1 – CT, FLNG2 – CT1, FLNG1 - PGT1, FLNG1 – PGT2, FLNG1 – PGT3, FLNG2 - PGT1, FLNG2 – PGT2, FLNG2 – PGT3, FSU-GCU	LAC 33.III Chapter 11	Does not apply	Does not apply to combustion units that combust only natural gas	LAC 33.III 1107 B.1
FLNG1 – CT, FLNG2 – CT, FLNG1 - PGT1, FLNG1 – PGT2, FLNG1 – PGT3, FLNG2 - PGT1,	40 CFR 63 Subpart YYYY	Exempt	Applies to stationary combustion turbines at a major source of HAP emissions and the Project will be a minor source of HAP emissions	40 CFR § 63.6080

TABLE 3: EXPLANATION FOR EXEMPTION STATUS OR NON-APPLICABILITY OF A SOURCE

Emission Point ID No:	Requirement	Exempt or Does Not Apply	Explanation	Citation Providing for Exemption or Non-applicability
FLNG2 – PGT2, FLNG2 – PGT3				
FSU-Boiler1, FSU-Boiler2	40 CFR 60 Subpart Dc	Exempt	Applies to boilers with a rated heat input between 10 and 100 MMBtu/hr. The FSU boilers have a rated heat input less than 10 MMBtu/hr	40 CFR § 60.40c(a)
FSU-Boiler1, FSU-Boiler2	40 CFR 63 Subpart DDDDD	Does not apply	Applies to boilers that are located at a major source of HAP emissions and the Project will be a minor source of HAP emissions. .	40 CFR § 63.7480
Storage Tanks	40 CFR 60 Subpart Kb	Exempt	The diesel fuel, waste oil, and lube oils stored in storage tanks has a maximum true vapor pressure less than 3.5 kilopascals	40 CFR § 60.110b(b)

The above table provides explanation for either the exemption status or non-applicability of a source cited by 2 or 3 in the matrix presented in Table 1 of this application.

TABLE 4: EQUIPMENT LIST

Enter each single emission point that routes its emissions to another source (i.e., a control device) or a common stack, or is part of an Emissions Cap. List the emissions source to which each single emission point is routed or the Cap of which the source is a member, if applicable. Consult instructions.

Emission Point ID No:	Description	Construction Date	Routes to:	Operating Rate/Volume	Applicable Requirement(s)?
FLNG1 Gas Treatment	FLNG1 gas treatment system waste acid gas sent to thermal oxidizer	January 2023	FLNG1-TO	9,097 kg/hr	☒ **Yes** ☐ **No**
FLNG2 Gas Treatment	FLNG2 gas treatment system waste acid gas sent to thermal oxidizer	January 2023	FLNG2-TO	9,097 kg/hr	☒ **Yes** ☐ **No**
					☐ **Yes** ☐ **No**
					☐ **Yes** ☐ **No**
					☐ **Yes** ☐ **No**
					☐ **Yes** ☐ **No**
					☐ **Yes** ☐ **No**
					☐ **Yes** ☐ **No**
					☐ **Yes** ☐ **No**
					☐ **Yes** ☐ **No**
					☐ **Yes** ☐ **No**
					☐ **Yes** ☐ **No**
					☐ **Yes** ☐ **No**
					☐ **Yes** ☐ **No**
					☐ **Yes** ☐ **No**
					☐ **Yes** ☐ **No**
					☐ **Yes** ☐ **No**
					☐ **Yes** ☐ **No**
					☐ **Yes** ☐ **No**
					☐ **Yes** ☐ **No**
					☐ **Yes** ☐ **No**

23. Emissions Inventory Questionnaire (EIQ) Forms [LAC 33:III.517.D.3; 517.D.6]

Complete one (1) EIQ for:

- Each emission source. If two emission sources have a common stack, the applicant may submit one EIQ sheet for the common emissions point. Note any emissions sources that route to this common point in Table 4 of the application.
- Each emissions CAP that is proposed, including each source that is part of the CAP.
- Each alternate operating scenario that a source may operate under. Some common scenarios are:
    1. Sources that combust multiple fuels
    2. Sources that have startup/shutdown max lb/hr emission rates higher than the max lb/hr for normal operating conditions would need a separate EIQ addressing the startup/shutdown emission rates
- Fugitive emissions releases. One (1) EIQ should be completed for each of the following types of fugitive emissions sources or emissions points:
    1. Equipment leaks.
    2. Non-equipment leaks (i.e., road dust, settling ponds, etc).

For each EIQ:

- Fill in all requested information.
- Speciate all Toxic Air Pollutants and Hazardous Air Pollutants emitted by the source.
- Use appropriate significant figures.
- Consult instructions.

The EIQ is in Microsoft Word Excel. Visit the following website to get to the EIQ form.
http://deq.louisiana.gov/page/air-permit-applications

24. NSR Applicability Summary [LAC 33:III.504 and LAC 33:III.509] ☐ N/A

This section consists of seven subsections, A-G, and is applicable only to new and existing major stationary sources (as defined in LAC 33:III.504 or in LAC 33:III.509) proposing to permit a physical change or change in the method of operation. It would also apply to existing minor stationary sources proposing a physical change or change in the method of operation where the change would be a major source in and of itself. Add rows to each table as necessary. Provide a written explanation of the information summarized in these tables. Consult instructions.

24.A. Project Summary

		A	B	C	D	E	F
Emission Point ID	**Description**	**New, Modified, Affected, or Unaffected***	**Pre-Project Allowables (TPY)**	**Baseline Actual Emissions (over 24-month period)**	**Projected Actual Emissions (TPY)**	**Post-Project Potential to Emit (TPY)**	**Change**
$PM_{2.5}$	**24-Month Period:** N/A New Facility						
FLNG1 – CT	FLNG1 Compressor Turbine	N	N/A	N/A	N/A	21.02	21.02
FLNG2 – CT1	FLNG2 Compressor Turbine	N	N/A	N/A	N/A	21.02	21.02
FLNG1 - PGT1	FLNG1 Power Generating Turbine 1	N	N/A	N/A	N/A	5.23	5.23
FLNG1 – PGT2	FLNG1 Power Generating Turbine 2	N	N/A	N/A	N/A	5.23	5.23
FLNG1 – PGT3	FLNG1 Power Generating Turbine 3	N	N/A	N/A	N/A	5.23	5.23
FLNG2 - PGT1	FLNG2 Power Generating Turbine 1	N	N/A	N/A	N/A	5.23	5.23
FLNG2 – PGT2	FLNG2 Power Generating Turbine 2	N	N/A	N/A	N/A	5.23	5.23
FLNG2 – PGT3	FLNG2 Power Generating Turbine 3	N	N/A	N/A	N/A	5.23	5.23
FLNG1-TO	FLNG1 Acid Gas Thermal Oxidizer	N	N/A	N/A	N/A	0.66	0.66
FLNG2-TO	FLNG2 Acid Gas Thermal Oxidizer	N	N/A	N/A	N/A	0.66	0.66
FLNG1-CF	FLNG1 Dry Flare	N	N/A	N/A	N/A	1.83	1.83
FLNG1-WF	FLNG1 Wet Flare	N	N/A	N/A	N/A	1.29	1.29
FLNG2-CF	FLNG2 Dry Flare	N	N/A	N/A	N/A	1.83	1.83
FLNG2-WF	FLNG2 Wet Flare	N	N/A	N/A	N/A	1.29	1.29
FLNG1-EDG1	FLNG1 Emergency Generator Engine 1	N	N/A	N/A	N/A	0.04	0.04
FLNG1-EDG2	FLNG1 Emergency Generator Engine 2	N	N/A	N/A	N/A	0.04	0.04

FLNG1-EDG3	FLNG1 Emergency Generator Engine 3	N	N/A	N/A	N/A	0.04	0.04
FLNG1-EDG4	FLNG1 Emergency Generator Engine 4	N	N/A	N/A	N/A	0.04	0.04
FLNG1-EDG5	FLNG1 Emergency Generator Engine 5	N	N/A	N/A	N/A	0.05	0.05
FLNG1-EDG6	FLNG1 Emergency Generator Engine 6	N	N/A	N/A	N/A	0.04	0.04
FLNG1-EDG7	FLNG1 Emergency Generator Engine 7	N	N/A	N/A	N/A	0.04	0.04
FLNG2-EDG1	FLNG2 Emergency Generator Engine 1	N	N/A	N/A	N/A	0.01	0.01
FLNG2-EDG2	FLNG2 Emergency Generator Engine 2	N	N/A	N/A	N/A	0.01	0.01
FLNG2-EDG3	FLNG2 Emergency Generator Engine 3	N	N/A	N/A	N/A	0.04	0.04
FLNG2-EDG4	FLNG2 Emergency Generator Engine 4	N	N/A	N/A	N/A	0.04	0.04
FLNG2-EDG5	FLNG2 Emergency Generator Engine 5	N	N/A	N/A	N/A	0.04	0.04
FLNG2-EDG6	FLNG2 Emergency Generator Engine 6	N	N/A	N/A	N/A	0.04	0.04
FLNG2-EDG7	FLNG2 Emergency Generator Engine 7	N	N/A	N/A	N/A	0.04	0.04
FLNG2-FP1	FLNG2 Emergency Fire Pump Engine 1	N	N/A	N/A	N/A	0.01	0.01
FLNG2-FP2	FLNG2 Emergency Fire Pump Engine 2	N	N/A	N/A	N/A	0.01	0.01
FLNG2-FP3	FLNG2 Emergency Fire Pump Engine 3	N	N/A	N/A	N/A	0.01	0.01
FLNG2-FP4	FLNG2 Emergency Fire Pump Engine 4	N	N/A	N/A	N/A	0.01	0.01
FLNG2-FP5	FLNG2 Emergency Fire Pump Engine 5	N	N/A	N/A	N/A	0.01	0.01
FLNG2-FP6	FLNG2 Emergency Fire Pump Engine 6	N	N/A	N/A	N/A	0.01	0.01
FLNG2-FP7	FLNG2 Emergency Fire Pump Engine 7	N	N/A	N/A	N/A	0.006	0.006
FLNG2-FP8	FLNG2 Emergency Fire Pump Engine 8	N	N/A	N/A	N/A	0.006	0.006
FSU-EDG	FSU Emergency Generator Engine	N	N/A	N/A	N/A	0.02	0.02
FSU-Boiler1	FSU Package Boiler 1	N	N/A	N/A	N/A	0.56	0.56
FSU-Boiler2	FSU Package Boiler 2	N	N/A	N/A	N/A	0.56	0.56
FSU-GCU	FSU Gas Combustion Unit	N	N/A	N/A	N/A	0.11	0.11
Equipment Leaks	Equipment Leaks	N	N/A	N/A	N/A	0	0

						$PM_{2.5}$ Change:	82.9

PM_{10}	**24-Month Period:** N/A New Facility						
FLNG1 – CT	FLNG1 Compressor Turbine	N	N/A	N/A	N/A	21.02	21.02
FLNG2 – CT1	FLNG2 Compressor Turbine	N	N/A	N/A	N/A	21.02	21.02
FLNG1 - PGT1	FLNG1 Power Generating Turbine 1	N	N/A	N/A	N/A	5.23	5.23
FLNG1 – PGT2	FLNG1 Power Generating Turbine 2	N	N/A	N/A	N/A	5.23	5.23
FLNG1 – PGT3	FLNG1 Power Generating Turbine 3	N	N/A	N/A	N/A	5.23	5.23
FLNG2 - PGT1	FLNG2 Power Generating Turbine 1	N	N/A	N/A	N/A	5.23	5.23
FLNG2 – PGT2	FLNG2 Power Generating Turbine 2	N	N/A	N/A	N/A	5.23	5.23
FLNG2 – PGT3	FLNG2 Power Generating Turbine 3	N	N/A	N/A	N/A	5.23	5.23
FLNG1-TO	FLNG1 Acid Gas Thermal Oxidizer	N	N/A	N/A	N/A	0.66	0.66
FLNG2-TO	FLNG2 Acid Gas Thermal Oxidizer	N	N/A	N/A	N/A	0.66	0.66
FLNG1-CF	FLNG1 Dry Flare	N	N/A	N/A	N/A	1.83	1.83
FLNG1-WF	FLNG1 Wet Flare	N	N/A	N/A	N/A	1.29	1.29
FLNG2-CF	FLNG2 Dry Flare	N	N/A	N/A	N/A	1.83	1.83
FLNG2-WF	FLNG2 Wet Flare	N	N/A	N/A	N/A	1.29	1.29
FLNG1-EDG1	FLNG1 Emergency Generator Engine 1	N	N/A	N/A	N/A	0.04	0.04
FLNG1-EDG2	FLNG1 Emergency Generator Engine 2	N	N/A	N/A	N/A	0.04	0.04
FLNG1-EDG3	FLNG1 Emergency Generator Engine 3	N	N/A	N/A	N/A	0.04	0.04
FLNG1-EDG4	FLNG1 Emergency Generator Engine 4	N	N/A	N/A	N/A	0.04	0.04
FLNG1-EDG5	FLNG1 Emergency Generator Engine 5	N	N/A	N/A	N/A	0.05	0.05
FLNG1-EDG6	FLNG1 Emergency Generator Engine 6	N	N/A	N/A	N/A	0.04	0.04
FLNG1-EDG7	FLNG1 Emergency Generator Engine 7	N	N/A	N/A	N/A	0.04	0.04
FLNG2-EDG1	FLNG2 Emergency Generator Engine 1	N	N/A	N/A	N/A	0.01	0.01
FLNG2-EDG2	FLNG2 Emergency Generator Engine 2	N	N/A	N/A	N/A	0.01	0.01

FLNG2-EDG3	FLNG2 Emergency Generator Engine 3	N	N/A	N/A	N/A	0.04	0.04
FLNG2-EDG4	FLNG2 Emergency Generator Engine 4	N	N/A	N/A	N/A	0.04	0.04
FLNG2-EDG5	FLNG2 Emergency Generator Engine 5	N	N/A	N/A	N/A	0.04	0.04
FLNG2-EDG6	FLNG2 Emergency Generator Engine 6	N	N/A	N/A	N/A	0.04	0.04
FLNG2-EDG7	FLNG2 Emergency Generator Engine 7	N	N/A	N/A	N/A	0.04	0.04
FLNG2-FP1	FLNG2 Emergency Fire Pump Engine 1	N	N/A	N/A	N/A	0.01	0.01
FLNG2-FP2	FLNG2 Emergency Fire Pump Engine 2	N	N/A	N/A	N/A	0.01	0.01
FLNG2-FP3	FLNG2 Emergency Fire Pump Engine 3	N	N/A	N/A	N/A	0.01	0.01
FLNG2-FP4	FLNG2 Emergency Fire Pump Engine 4	N	N/A	N/A	N/A	0.01	0.01
FLNG2-FP5	FLNG2 Emergency Fire Pump Engine 5	N	N/A	N/A	N/A	0.01	0.01
FLNG2-FP6	FLNG2 Emergency Fire Pump Engine 6	N	N/A	N/A	N/A	0.01	0.01
FLNG2-FP7	FLNG2 Emergency Fire Pump Engine 7	N	N/A	N/A	N/A	0.006	0.006
FLNG2-FP8	FLNG2 Emergency Fire Pump Engine 8	N	N/A	N/A	N/A	0.006	0.006
FSU-EDG	FSU Emergency Generator Engine	N	N/A	N/A	N/A	0.02	0.02
FSU-Boiler1	FSU Package Boiler 1	N	N/A	N/A	N/A	0.56	0.56
FSU-Boiler2	FSU Package Boiler 2	N	N/A	N/A	N/A	0.56	0.56
FSU-GCU	FSU Gas Combustion Unit	N	N/A	N/A	N/A	0.11	0.11
Equipment Leaks	Equipment Leaks	N	N/A	N/A	N/A	0	0
						PM_{10} Change:	82.9

SO_2	**24-Month Period:** N/A New Facility						
FLNG1 – CT	FLNG1 Compressor Turbine	N	N/A	N/A	N/A	6.33	6.33
FLNG2 – CT1	FLNG2 Compressor Turbine	N	N/A	N/A	N/A	6.33	6.33
FLNG1 - PGT1	FLNG1 Power Generating Turbine 1	N	N/A	N/A	N/A	2.29	2.29
FLNG1 – PGT2	FLNG1 Power Generating Turbine 2	N	N/A	N/A	N/A	2.29	2.29
FLNG1 – PGT3	FLNG1 Power Generating Turbine 3	N	N/A	N/A	N/A	2.29	2.29

FLNG2 - PGT1	FLNG2 Power Generating Turbine 1	N	N/A	N/A	N/A	2.29	2.29
FLNG2 – PGT2	FLNG2 Power Generating Turbine 2	N	N/A	N/A	N/A	2.29	2.29
FLNG2 – PGT3	FLNG2 Power Generating Turbine 3	N	N/A	N/A	N/A	2.29	2.29
FLNG1-TO	FLNG1 Acid Gas Thermal Oxidizer	N	N/A	N/A	N/A	36.45	36.45
FLNG2-TO	FLNG2 Acid Gas Thermal Oxidizer	N	N/A	N/A	N/A	36.45	36.45
FLNG1-CF	FLNG1 Dry Flare	N	N/A	N/A	N/A	0.74	0.74
FLNG1-WF	FLNG1 Wet Flare	N	N/A	N/A	N/A	0.52	0.52
FLNG2-CF	FLNG2 Dry Flare	N	N/A	N/A	N/A	0.74	0.74
FLNG2-WF	FLNG2 Wet Flare	N	N/A	N/A	N/A	0.52	0.52
FLNG1-EDG1	FLNG1 Emergency Generator Engine 1	N	N/A	N/A	N/A	0.001	0.001
FLNG1-EDG2	FLNG1 Emergency Generator Engine 2	N	N/A	N/A	N/A	0.001	0.001
FLNG1-EDG3	FLNG1 Emergency Generator Engine 3	N	N/A	N/A	N/A	0.001	0.001
FLNG1-EDG4	FLNG1 Emergency Generator Engine 4	N	N/A	N/A	N/A	0.001	0.001
FLNG1-EDG5	FLNG1 Emergency Generator Engine 5	N	N/A	N/A	N/A	0.001	0.001
FLNG1-EDG6	FLNG1 Emergency Generator Engine 6	N	N/A	N/A	N/A	0.001	0.001
FLNG1-EDG7	FLNG1 Emergency Generator Engine 7	N	N/A	N/A	N/A	0.001	0.001
FLNG2-EDG1	FLNG2 Emergency Generator Engine 1	N	N/A	N/A	N/A	0.0004	0.0004
FLNG2-EDG2	FLNG2 Emergency Generator Engine 2	N	N/A	N/A	N/A	0.0004	0.0004
FLNG2-EDG3	FLNG2 Emergency Generator Engine 3	N	N/A	N/A	N/A	0.0004	0.0004
FLNG2-EDG4	FLNG2 Emergency Generator Engine 4	N	N/A	N/A	N/A	0.0004	0.0004
FLNG2-EDG5	FLNG2 Emergency Generator Engine 5	N	N/A	N/A	N/A	0.0004	0.0004
FLNG2-EDG6	FLNG2 Emergency Generator Engine 6	N	N/A	N/A	N/A	0.0002	0.0002
FLNG2-EDG7	FLNG2 Emergency Generator Engine 7	N	N/A	N/A	N/A	0.0002	0.0002
FLNG2-FP1	FLNG2 Emergency Fire Pump Engine 1	N	N/A	N/A	N/A	0.001	0.001
FLNG2-FP2	FLNG2 Emergency Fire Pump Engine 2	N	N/A	N/A	N/A	0.001	0.001

FLNG2-FP3	FLNG2 Emergency Fire Pump Engine 3	N	N/A	N/A	N/A	0.001	0.001
FLNG2-FP4	FLNG2 Emergency Fire Pump Engine 4	N	N/A	N/A	N/A	0.001	0.001
FLNG2-FP5	FLNG2 Emergency Fire Pump Engine 5	N	N/A	N/A	N/A	0.001	0.001
FLNG2-FP6	FLNG2 Emergency Fire Pump Engine 6	N	N/A	N/A	N/A	0.001	0.001
FLNG2-FP7	FLNG2 Emergency Fire Pump Engine 7	N	N/A	N/A	N/A	0.0002	0.0002
FLNG2-FP8	FLNG2 Emergency Fire Pump Engine 8	N	N/A	N/A	N/A	0.0002	0.0002
FSU-EDG	FSU Emergency Generator Engine	N	N/A	N/A	N/A	0.001	0.001
FSU-Boiler1	FSU Package Boiler 1	N	N/A	N/A	N/A	2.41	2.41
FSU-Boiler2	FSU Package Boiler 2	N	N/A	N/A	N/A	2.41	2.41
FSU-GCU	FSU Gas Combustion Unit	N	N/A	N/A	N/A	0.043	0.043
Equipment Leaks	Equipment Leaks	N	N/A	N/A	N/A	0	0
						SO_2 Change:	106.7

NO_X	**24-Month Period:** N/A New Facility						
FLNG1 – CT	FLNG1 Compressor Turbine	N	N/A	N/A	N/A	194.4	194.4
FLNG2 – CT1	FLNG2 Compressor Turbine	N	N/A	N/A	N/A	116.7	116.7
FLNG1 - PGT1	FLNG1 Power Generating Turbine 1	N	N/A	N/A	N/A	41.6	41.6
FLNG1 – PGT2	FLNG1 Power Generating Turbine 2	N	N/A	N/A	N/A	41.6	41.6
FLNG1 – PGT3	FLNG1 Power Generating Turbine 3	N	N/A	N/A	N/A	41.6	41.6
FLNG2 - PGT1	FLNG2 Power Generating Turbine 1	N	N/A	N/A	N/A	41.6	41.6
FLNG2 – PGT2	FLNG2 Power Generating Turbine 2	N	N/A	N/A	N/A	41.6	41.6
FLNG2 – PGT3	FLNG2 Power Generating Turbine 3	N	N/A	N/A	N/A	41.6	41.6
FLNG1-TO	FLNG1 Acid Gas Thermal Oxidizer	N	N/A	N/A	N/A	6.6	6.6
FLNG2-TO	FLNG2 Acid Gas Thermal Oxidizer	N	N/A	N/A	N/A	6.6	6.6
FLNG1-CF	FLNG1 Dry Flare	N	N/A	N/A	N/A	34.0	34.0
FLNG1-WF	FLNG1 Wet Flare	N	N/A	N/A	N/A	23.8	23.8

FLNG2-CF	FLNG2 Dry Flare	N	N/A	N/A	N/A	34.0	34.0
FLNG2-WF	FLNG2 Wet Flare	N	N/A	N/A	N/A	23.8	23.8
FLNG1-EDG1	FLNG1 Emergency Generator Engine 1	N	N/A	N/A	N/A	3.26	3.26
FLNG1-EDG2	FLNG1 Emergency Generator Engine 2	N	N/A	N/A	N/A	3.26	3.26
FLNG1-EDG3	FLNG1 Emergency Generator Engine 3	N	N/A	N/A	N/A	3.26	3.26
FLNG1-EDG4	FLNG1 Emergency Generator Engine 4	N	N/A	N/A	N/A	3.26	3.26
FLNG1-EDG5	FLNG1 Emergency Generator Engine 5	N	N/A	N/A	N/A	1.74	1.74
FLNG1-EDG6	FLNG1 Emergency Generator Engine 6	N	N/A	N/A	N/A	3.26	3.26
FLNG1-EDG7	FLNG1 Emergency Generator Engine 7	N	N/A	N/A	N/A	3.26	3.26
FLNG2-EDG1	FLNG2 Emergency Generator Engine 1	N	N/A	N/A	N/A	0.42	0.42
FLNG2-EDG2	FLNG2 Emergency Generator Engine 2	N	N/A	N/A	N/A	0.42	0.42
FLNG2-EDG3	FLNG2 Emergency Generator Engine 3	N	N/A	N/A	N/A	1.77	1.77
FLNG2-EDG4	FLNG2 Emergency Generator Engine 4	N	N/A	N/A	N/A	1.77	1.77
FLNG2-EDG5	FLNG2 Emergency Generator Engine 5	N	N/A	N/A	N/A	1.77	1.77
FLNG2-EDG6	FLNG2 Emergency Generator Engine 6	N	N/A	N/A	N/A	1.77	1.77
FLNG2-EDG7	FLNG2 Emergency Generator Engine 7	N	N/A	N/A	N/A	1.77	1.77
FLNG2-FP1	FLNG2 Emergency Fire Pump Engine 1	N	N/A	N/A	N/A	0.42	0.42
FLNG2-FP2	FLNG2 Emergency Fire Pump Engine 2	N	N/A	N/A	N/A	0.42	0.42
FLNG2-FP3	FLNG2 Emergency Fire Pump Engine 3	N	N/A	N/A	N/A	0.42	0.42
FLNG2-FP4	FLNG2 Emergency Fire Pump Engine 4	N	N/A	N/A	N/A	0.42	0.42
FLNG2-FP5	FLNG2 Emergency Fire Pump Engine 5	N	N/A	N/A	N/A	0.42	0.42
FLNG2-FP6	FLNG2 Emergency Fire Pump Engine 6	N	N/A	N/A	N/A	0.42	0.42
FLNG2-FP7	FLNG2 Emergency Fire Pump Engine 7	N	N/A	N/A	N/A	0.12	0.12
FLNG2-FP8	FLNG2 Emergency Fire Pump Engine 8	N	N/A	N/A	N/A	0.12	0.12
FSU-EDG	FSU Emergency Generator Engine	N	N/A	N/A	N/A	0.60	0.60

FSU-Boiler1	FSU Package Boiler 1	N	N/A	N/A	N/A	3.40	3.40
FSU-Boiler2	FSU Package Boiler 2	N	N/A	N/A	N/A	3.40	3.40
FSU-GCU	FSU Gas Combustion Unit	N	N/A	N/A	N/A	1.42	1.42
Equipment Leaks	Equipment Leaks	N	N/A	N/A	N/A	0	0
						NO_X Change:	737.9
CO	**24-Month Period:** N/A New Facility						
FLNG1 – CT	FLNG1 Compressor Turbine	N	N/A	N/A	N/A	118.4	118.4
FLNG2 – CT1	FLNG2 Compressor Turbine	N	N/A	N/A	N/A	118.4	118.4
FLNG1 - PGT1	FLNG1 Power Generating Turbine 1	N	N/A	N/A	N/A	25.3	25.3
FLNG1 – PGT2	FLNG1 Power Generating Turbine 2	N	N/A	N/A	N/A	25.3	25.3
FLNG1 – PGT3	FLNG1 Power Generating Turbine 3	N	N/A	N/A	N/A	25.3	25.3
FLNG2 - PGT1	FLNG2 Power Generating Turbine 1	N	N/A	N/A	N/A	25.3	25.3
FLNG2 – PGT2	FLNG2 Power Generating Turbine 2	N	N/A	N/A	N/A	25.3	25.3
FLNG2 – PGT3	FLNG2 Power Generating Turbine 3	N	N/A	N/A	N/A	25.3	25.3
FLNG1-TO	FLNG1 Acid Gas Thermal Oxidizer	N	N/A	N/A	N/A	18.3	18.3
FLNG2-TO	FLNG2 Acid Gas Thermal Oxidizer	N	N/A	N/A	N/A	18.3	18.3
FLNG1-CF	FLNG1 Dry Flare	N	N/A	N/A	N/A	67.8	67.8
FLNG1-WF	FLNG1 Wet Flare	N	N/A	N/A	N/A	47.6	47.6
FLNG2-CF	FLNG2 Dry Flare	N	N/A	N/A	N/A	67.8	67.8
FLNG2-WF	FLNG2 Wet Flare	N	N/A	N/A	N/A	47.6	47.6
FLNG1-EDG1	FLNG1 Emergency Generator Engine 1	N	N/A	N/A	N/A	0.7	0.7
FLNG1-EDG2	FLNG1 Emergency Generator Engine 2	N	N/A	N/A	N/A	0.7	0.7
FLNG1-EDG3	FLNG1 Emergency Generator Engine 3	N	N/A	N/A	N/A	0.7	0.7
FLNG1-EDG4	FLNG1 Emergency Generator Engine 4	N	N/A	N/A	N/A	0.7	0.7
FLNG1-EDG5	FLNG1 Emergency Generator Engine 5	N	N/A	N/A	N/A	0.4	0.4

FLNG1-EDG6	FLNG1 Emergency Generator Engine 6	N	N/A	N/A	N/A	0.7	0.7
FLNG1-EDG7	FLNG1 Emergency Generator Engine 7	N	N/A	N/A	N/A	0.7	0.7
FLNG2-EDG1	FLNG2 Emergency Generator Engine 1	N	N/A	N/A	N/A	0.2	0.2
FLNG2-EDG2	FLNG2 Emergency Generator Engine 2	N	N/A	N/A	N/A	0.2	0.2
FLNG2-EDG3	FLNG2 Emergency Generator Engine 3	N	N/A	N/A	N/A	0.7	0.7
FLNG2-EDG4	FLNG2 Emergency Generator Engine 4	N	N/A	N/A	N/A	0.7	0.7
FLNG2-EDG5	FLNG2 Emergency Generator Engine 5	N	N/A	N/A	N/A	0.7	0.7
FLNG2-EDG6	FLNG2 Emergency Generator Engine 6	N	N/A	N/A	N/A	0.7	0.7
FLNG2-EDG7	FLNG2 Emergency Generator Engine 7	N	N/A	N/A	N/A	0.7	0.7
FLNG2-FP1	FLNG2 Emergency Fire Pump Engine 1	N	N/A	N/A	N/A	0.2	0.2
FLNG2-FP2	FLNG2 Emergency Fire Pump Engine 2	N	N/A	N/A	N/A	0.2	0.2
FLNG2-FP3	FLNG2 Emergency Fire Pump Engine 3	N	N/A	N/A	N/A	0.2	0.2
FLNG2-FP4	FLNG2 Emergency Fire Pump Engine 4	N	N/A	N/A	N/A	0.2	0.2
FLNG2-FP5	FLNG2 Emergency Fire Pump Engine 5	N	N/A	N/A	N/A	0.2	0.2
FLNG2-FP6	FLNG2 Emergency Fire Pump Engine 6	N	N/A	N/A	N/A	0.2	0.2
FLNG2-FP7	FLNG2 Emergency Fire Pump Engine 7	N	N/A	N/A	N/A	0.1	0.1
FLNG2-FP8	FLNG2 Emergency Fire Pump Engine 8	N	N/A	N/A	N/A	0.1	0.1
FSU-EDG	FSU Emergency Generator Engine	N	N/A	N/A	N/A	0.3	0.3
FSU-Boiler1	FSU Package Boiler 1	N	N/A	N/A	N/A	0.9	0.9
FSU-Boiler2	FSU Package Boiler 2	N	N/A	N/A	N/A	0.9	0.9
FSU-GCU	FSU Gas Combustion Unit	N	N/A	N/A	N/A	1.2	1.2
Equipment Leaks	Equipment Leaks	N	N/A	N/A	N/A	0	0
						CO Change:	669.3

VOC	**24-Month Period:** N/A New Facility						
FLNG1 – CT	FLNG1 Compressor Turbine	N	N/A	N/A	N/A	8.13	8.13

FLNG2 – CT1	FLNG2 Compressor Turbine	N	N/A	N/A	N/A	8.13	8.13
FLNG1 - PGT1	FLNG1 Power Generating Turbine 1	N	N/A	N/A	N/A	1.48	1.48
FLNG1 – PGT2	FLNG1 Power Generating Turbine 2	N	N/A	N/A	N/A	1.48	1.48
FLNG1 – PGT3	FLNG1 Power Generating Turbine 3	N	N/A	N/A	N/A	1.48	1.48
FLNG2 - PGT1	FLNG2 Power Generating Turbine 1	N	N/A	N/A	N/A	1.48	1.48
FLNG2 – PGT2	FLNG2 Power Generating Turbine 2	N	N/A	N/A	N/A	1.48	1.48
FLNG2 – PGT3	FLNG2 Power Generating Turbine 3	N	N/A	N/A	N/A	1.48	1.48
FLNG1-TO	FLNG1 Acid Gas Thermal Oxidizer	N	N/A	N/A	N/A	0.54	0.54
FLNG2-TO	FLNG2 Acid Gas Thermal Oxidizer	N	N/A	N/A	N/A	0.54	0.54
FLNG1-CF	FLNG1 Dry Flare	N	N/A	N/A	N/A	4.1	4.1
FLNG1-WF	FLNG1 Wet Flare	N	N/A	N/A	N/A	1.6	1.6
FLNG2-CF	FLNG2 Dry Flare	N	N/A	N/A	N/A	4.1	4.1
FLNG2-WF	FLNG2 Wet Flare	N	N/A	N/A	N/A	1.6	1.6
FLNG1-EDG1	FLNG1 Emergency Generator Engine 1	N	N/A	N/A	N/A	0.02	0.02
FLNG1-EDG2	FLNG1 Emergency Generator Engine 2	N	N/A	N/A	N/A	0.02	0.02
FLNG1-EDG3	FLNG1 Emergency Generator Engine 3	N	N/A	N/A	N/A	0.02	0.02
FLNG1-EDG4	FLNG1 Emergency Generator Engine 4	N	N/A	N/A	N/A	0.02	0.02
FLNG1-EDG5	FLNG1 Emergency Generator Engine 5	N	N/A	N/A	N/A	0.04	0.04
FLNG1-EDG6	FLNG1 Emergency Generator Engine 6	N	N/A	N/A	N/A	0.02	0.02
FLNG1-EDG7	FLNG1 Emergency Generator Engine 7	N	N/A	N/A	N/A	0.02	0.02
FLNG2-EDG1	FLNG2 Emergency Generator Engine 1	N	N/A	N/A	N/A	0.01	0.01
FLNG2-EDG2	FLNG2 Emergency Generator Engine 2	N	N/A	N/A	N/A	0.01	0.01
FLNG2-EDG3	FLNG2 Emergency Generator Engine 3	N	N/A	N/A	N/A	0.04	0.04
FLNG2-EDG4	FLNG2 Emergency Generator Engine 4	N	N/A	N/A	N/A	0.04	0.04
FLNG2-EDG5	FLNG2 Emergency Generator Engine 5	N	N/A	N/A	N/A	0.04	0.04

FLNG2-EDG6	FLNG2 Emergency Generator Engine 6	N	N/A	N/A	N/A	0.04	0.04
FLNG2-EDG7	FLNG2 Emergency Generator Engine 7	N	N/A	N/A	N/A	0.04	0.04
FLNG2-FP1	FLNG2 Emergency Fire Pump Engine 1	N	N/A	N/A	N/A	0.08	0.08
FLNG2-FP2	FLNG2 Emergency Fire Pump Engine 2	N	N/A	N/A	N/A	0.08	0.08
FLNG2-FP3	FLNG2 Emergency Fire Pump Engine 3	N	N/A	N/A	N/A	0.08	0.08
FLNG2-FP4	FLNG2 Emergency Fire Pump Engine 4	N	N/A	N/A	N/A	0.08	0.08
FLNG2-FP5	FLNG2 Emergency Fire Pump Engine 5	N	N/A	N/A	N/A	0.08	0.08
FLNG2-FP6	FLNG2 Emergency Fire Pump Engine 6	N	N/A	N/A	N/A	0.08	0.08
FLNG2-FP7	FLNG2 Emergency Fire Pump Engine 7	N	N/A	N/A	N/A	0.04	0.04
FLNG2-FP8	FLNG2 Emergency Fire Pump Engine 8	N	N/A	N/A	N/A	0.04	0.04
FSU-EDG	FSU Emergency Generator Engine	N	N/A	N/A	N/A	0.11	0.11
FSU-Boiler1	FSU Package Boiler 1	N	N/A	N/A	N/A	0.13	0.13
FSU-Boiler2	FSU Package Boiler 2	N	N/A	N/A	N/A	0.13	0.13
FSU-GCU	FSU Gas Combustion Unit	N	N/A	N/A	N/A	0.08	0.08
Equipment Leaks	Equipment Leaks	N	N/A	N/A	N/A	0.50	0.50
Oil Storage Tanks	Oil Storage Tanks	N	N/A	N/A	N/A	0.27	0.27
						VOC Change:	41.0

CO_2e	**24-Month Period:** N/A New Facility						
FLNG1 – CT	FLNG1 Compressor Turbine	N	N/A	N/A	N/A	247,029	247,029
FLNG2 – CT1	FLNG2 Compressor Turbine	N	N/A	N/A	N/A	247,029	247,029
FLNG1 - PGT1	FLNG1 Power Generating Turbine 1	N	N/A	N/A	N/A	89,152	89,152
FLNG1 – PGT2	FLNG1 Power Generating Turbine 2	N	N/A	N/A	N/A	89,152	89,152
FLNG1 – PGT3	FLNG1 Power Generating Turbine 3	N	N/A	N/A	N/A	89,152	89,152
FLNG2 - PGT1	FLNG2 Power Generating Turbine 1	N	N/A	N/A	N/A	89,152	89,152

FLNG2 – PGT2	FLNG2 Power Generating Turbine 2	N	N/A	N/A	N/A	89,152	89,152
FLNG2 – PGT3	FLNG2 Power Generating Turbine 3	N	N/A	N/A	N/A	89,152	89,152
FLNG1-TO	FLNG1 Acid Gas Thermal Oxidizer	N	N/A	N/A	N/A	92,366	92,366
FLNG2-TO	FLNG2 Acid Gas Thermal Oxidizer	N	N/A	N/A	N/A	92,366	92,366
FLNG1-CF	FLNG1 Dry Flare	N	N/A	N/A	N/A	29,050	31,328
FLNG1-WF	FLNG1 Wet Flare	N	N/A	N/A	N/A	21,031	21,963
FLNG2-CF	FLNG2 Dry Flare	N	N/A	N/A	N/A	29,050	31,328
FLNG2-WF	FLNG2 Wet Flare	N	N/A	N/A	N/A	21,031	21,963
FLNG1-EDG1	FLNG1 Emergency Generator Engine 1	N	N/A	N/A	N/A	140	140
FLNG1-EDG2	FLNG1 Emergency Generator Engine 2	N	N/A	N/A	N/A	140	140
FLNG1-EDG3	FLNG1 Emergency Generator Engine 3	N	N/A	N/A	N/A	140	140
FLNG1-EDG4	FLNG1 Emergency Generator Engine 4	N	N/A	N/A	N/A	140	140
FLNG1-EDG5	FLNG1 Emergency Generator Engine 5	N	N/A	N/A	N/A	91	91
FLNG1-EDG6	FLNG1 Emergency Generator Engine 6	N	N/A	N/A	N/A	140	140
FLNG1-EDG7	FLNG1 Emergency Generator Engine 7	N	N/A	N/A	N/A	140	140
FLNG2-EDG1	FLNG2 Emergency Generator Engine 1	N	N/A	N/A	N/A	45	45
FLNG2-EDG2	FLNG2 Emergency Generator Engine 2	N	N/A	N/A	N/A	45	45
FLNG2-EDG3	FLNG2 Emergency Generator Engine 3	N	N/A	N/A	N/A	132	132
FLNG2-EDG4	FLNG2 Emergency Generator Engine 4	N	N/A	N/A	N/A	132	132
FLNG2-EDG5	FLNG2 Emergency Generator Engine 5	N	N/A	N/A	N/A	132	132
FLNG2-EDG6	FLNG2 Emergency Generator Engine 6	N	N/A	N/A	N/A	132	132
FLNG2-EDG7	FLNG2 Emergency Generator Engine 7	N	N/A	N/A	N/A	132	132
FLNG2-FP1	FLNG2 Emergency Fire Pump Engine 1	N	N/A	N/A	N/A	45	45
FLNG2-FP2	FLNG2 Emergency Fire Pump Engine 2	N	N/A	N/A	N/A	45	45
FLNG2-FP3	FLNG2 Emergency Fire Pump Engine 3	N	N/A	N/A	N/A	45	45

FLNG2-FP4	FLNG2 Emergency Fire Pump Engine 4	N	N/A	N/A	N/A	45	45
FLNG2-FP5	FLNG2 Emergency Fire Pump Engine 5	N	N/A	N/A	N/A	45	45
FLNG2-FP6	FLNG2 Emergency Fire Pump Engine 6	N	N/A	N/A	N/A	45	45
FLNG2-FP7	FLNG2 Emergency Fire Pump Engine 7	N	N/A	N/A	N/A	20	20
FLNG2-FP8	FLNG2 Emergency Fire Pump Engine 8	N	N/A	N/A	N/A	20	20
FSU-EDG	FSU Emergency Generator Engine	N	N/A	N/A	N/A	64	64
FSU-Boiler1	FSU Package Boiler 1	N	N/A	N/A	N/A	3,833	3,833
FSU-Boiler2	FSU Package Boiler 2	N	N/A	N/A	N/A	3,833	3,833
FSU-GCU	FSU Gas Combustion Unit	N	N/A	N/A	N/A	1,675	1,675
Equipment Leaks	Equipment Leaks	N	N/A	N/A	N/A	87	87
						CO_2e Change:	1,332,401

* Unaffected emissions units are not required to be listed individually. By choosing not to list unaffected emissions units, the applicant asserts that all emissions units not listed in Table 24.A will not be modified or experience an increase in actual annual emissions as part of the proposed project.

24.B. Creditable Contemporaneous Changes (N/A)

Contemporaneous Period: N/A New Facility	

		A	B	C	D	E	F
Emission Point ID	**Description**	**Date of Modification**	**Pre-Project Allowables (TPY)**	**Baseline Actual Emissions (over 24-month period)**	**24-Month Period**	**Post-Project Potential to Emit (TPY)**	**Change**
$PM_{2.5}$							
N/A							
						$PM_{2.5}$ Change:	
PM_{10}							
N/A							
						PM_{10} Change:	

24.B. Creditable Contemporaneous Changes (N/A)

SO_2							
N/A							
						SO_2 Change:	

NO_X							
N/A							
						NO_X Change:	

CO							
N/A							
						CO Change:	

VOC							
N/A							
						VOC Change:	

CO_2e							
N/A							
						CO_2e Change:	

For each source identified as "New" or "Modified" in Section 24.A, complete the following table for each pollutant that will trigger NSR. If LAER is not required per LAC 33:III.504.D.3, indicate such.

24.C. BACT Summary

Emission Point ID	Pollutant	BACT	Limitation	Averaging Period	Description of Control Technology/Work Practice Standard(s)
FLNG1-CT	NO_X	LAC 33:III.509	25 ppm by volume dry basis at 15% O2 (ppmvdc)	4-hour	Dry Low NOx Combustor
	CO		25 ppmvdc	3-hour	Good combustion practices
	VOC		3.0 ppmvdc	3-hour	Good combustion practices

Emission Point ID	Pollutant	BACT	Limitation	Averaging Period	Description of Control Technology/Work Practice Standard(s)
	$PM_{10}/PM_{2.5}$		0.010 pounds per million Btu HHV (lb/MMBtu)	3-hour	Natural gas as the sole fuel, good combustion practices
	SO_2		sulfur content ≤20 ppmv	N/A	Natural gas as the sole fuel
	H_2SO_4		sulfur content ≤20 ppmv	N/A	Natural gas as the sole fuel
	GHG		247,029 tons per year (tpy) per unit	Annual as CO_2e	Natural gas as the sole fuel, efficient turbine operation
FLNG2-CT1	NO_X	LAC 33:III.509	15 ppm by volume dry basis at 15% O2 (ppmvdc)	4-hour	Dry Low NOx Combustor & Selective Catalytic Reduction
	CO		25 ppmvdc	3-hour	Good combustion practices
	VOC		3.0 ppmvdc	3-hour	Good combustion practices
	$PM_{10}/PM_{2.5}$		0.010 pounds per million Btu HHV (lb/MMBtu)	3-hour	Natural gas as the sole fuel, good combustion practices
	SO_2		sulfur content ≤20 ppmv	N/A	Natural gas as the sole fuel
	H_2SO_4		sulfur content ≤20 ppmv	N/A	Natural gas as the sole fuel
	GHG		247,029 tons per year (tpy) per unit	Annual as CO_2e	Natural gas as the sole fuel, efficient turbine operation
FLNG1 - PGT1	NO_X	LAC 33:III.509	15 ppmvdc	4-hour	Dry Low NOx Combustor
FLNG1 – PGT2	CO		15 ppmvdc	3-hour	Good combustion practices
FLNG1 – PGT3	VOC		1.4 ppmvdc	3-hour	Good combustion practices
FLNG1 – PGT4	$PM_{10}/PM_{2.5}$		0.007 lb/MMBtu	3-hour	Natural gas as the sole fuel, good combustion practices
FLNG1 – PGT5	SO_2		sulfur content ≤20 ppmv	N/A	Natural gas as the sole fuel
FLNG1 – PGT6	H_2SO_4		sulfur content ≤20 ppmv	N/A	Natural gas as the sole fuel
	GHG		89,152 tpy per unit	Annual as CO_2e	Natural gas as the sole fuel, efficient turbine operation
FLNG2-CT2	NO_X	LAC 33:III.509	15 ppmvdc	4-hour	Dry Low NOx Combustor
FLNG2-CT3	CO		25 ppmvdc	3-hour	Good combustion practices
FLNG2-CT4	VOC		5.0 ppmvdc	3-hour	Good combustion practices
	$PM_{10}/PM_{2.5}$		0.10 lb/MMBtu	3-hour	Natural gas as the sole fuel, good combustion practices
	SO_2		sulfur content ≤20 ppmv	N/A	Natural gas as the sole fuel
	H_2SO_4		sulfur content ≤20 ppmv	N/A	Natural gas as the sole fuel
	GHG		44,834 tpy per unit	Annual as CO_2e	Natural gas as the sole fuel, efficient turbine operation

Emission Point ID	Pollutant	BACT	Limitation	Averaging Period	Description of Control Technology/Work Practice Standard(s)
FLNG1-TO FLNG2-TO	NO_X	LAC 33:III.509	0.10 lb/MMBtu	3-hour	Low NO_X Burners
	CO		0.28 lb/MMBtu	3-hour	Good combustion practices
	VOC		0.12 lb/hr	3-hour	Good combustion practices. 99.9% destruction
	$PM_{10}/PM_{2.5}$		0.010 lb/MMBtu	3-hour	Good combustion practices
	SO_2		8.3 lb/hr	3-hour	Natural gas as the sole fuel
	H_2SO_4		0.64 lb/hr	3-hour	Natural gas as the sole fuel
	GHG		92,366 tpy per unit	Annual as CO_2e	Natural gas as the sole fuel
FLNG1-CF FLNG2-CF	NO_X	LAC 33:III.509	0.138 lb/MMBtu	3-hour	Good combustion practices
	CO		0.28 lb/MMBtu	3-hour	Good combustion practices
	VOC		99% Control	3-hour	Good combustion practices. 99% destruction
	$PM_{10}/PM_{2.5}$		0.0075 lb/MMBtu	3-hour	Good combustion practices
	SO_2		sulfur content ≤20 ppmv	N/A	Natural gas as the sole fuel
	H_2SO_4		sulfur content ≤20 ppmv	N/A	Natural gas as the sole fuel
	GHG		31,328 tpy per unit	Annual as CO_2e	Natural gas as the sole fuel
FLNG1-WF FLNG2-WF	NO_X	LAC 33:III.509	0.138 lb/MMBtu	3-hour	Good combustion practices
	CO		0.28 lb/MMBtu	3-hour	Good combustion practices
	VOC		99% Control	3-hour	Good combustion practices. 99% destruction
	$PM_{10}/PM_{2.5}$		0.0075 lb/MMBtu	3-hour	Good combustion practices
	SO_2		sulfur content ≤20 ppmv	N/A	Natural gas as the sole fuel
	H_2SO_4		sulfur content ≤20 ppmv	N/A	Natural gas as the sole fuel
	GHG		21,963 tpy per unit	Annual as CO_2e	Natural gas as the sole fuel
FLNG1-EDG1 FLNG1-EDG2 FLNG1-EDG3 FLNG1-EDG4 FLNG1-EDG6 FLNG1-EDG7	NO_X	LAC 33:III.509	16.92 g/kW-hr	N/A	Operate in accordance with manufacturer recommendations. Good combustion practices
	CO		3.5 g/kW-hr	N/A	Operate in accordance with manufacturer recommendations. Good combustion practices
	$PM_{10}/PM_{2.5}$		0.20 g/kW-hr	N/A	Operate in accordance with manufacturer recommendations. Good combustion practices
	VOC		0.08 g/kW-hr	N/A	Operate in accordance with manufacturer recommendations. Good combustion practices
	SO_2		sulfur content ≤15 ppmw	N/A	Ultra low sulfur diesel as sole fuel
	H_2SO_4		sulfur content ≤15 ppmw	N/A	Ultra low sulfur diesel as sole fuel
	GHG		140 tpy per unit	Annual as CO_2e	Efficient engine design

Emission Point ID	Pollutant	BACT	Limitation	Averaging Period	Description of Control Technology/Work Practice Standard(s)
FLNG1-EDG5	NO_X	LAC 33:III.509	14.35 g/kW-hr	N/A	Operate in accordance with manufacturer recommendations. Good combustion practices
	CO		3.5 g/kW-hr	N/A	Operate in accordance with manufacturer recommendations. Good combustion practices
	$PM_{10}/PM_{2.5}$		0.44 g/kW-hr	N/A	Operate in accordance with manufacturer recommendations. Good combustion practices
	VOC		0.30 g/kW-hr	N/A	Operate in accordance with manufacturer recommendations. Good combustion practices
	SO_2		sulfur content $\leq$15 ppmw	N/A	Ultra low sulfur diesel as sole fuel
	H_2SO_4		sulfur content $\leq$15 ppmw	N/A	Ultra low sulfur diesel as sole fuel
	GHG		91 tpy	Annual as CO_2e	Efficient engine design
FLNG2-EDG1 FLNG2-EDG2	NO_X	LAC 33:III.509	6.40 g/kW-hr	N/A	NSPS Subpart IIII emissions compliance
	CO		3.5 g/kW-hr	N/A	NSPS Subpart IIII emissions compliance
	$PM_{10}/PM_{2.5}$		0.20 g/kW-hr	N/A	NSPS Subpart IIII emissions compliance
	VOC		0.10 g/kW-hr	N/A	NSPS Subpart IIII emissions compliance
	SO_2		sulfur content $\leq$15 ppmw	N/A	Ultra low sulfur diesel as sole fuel
	H_2SO_4		sulfur content $\leq$15 ppmw	N/A	Ultra low sulfur diesel as sole fuel
	GHG		45 tpy per unit	Annual as CO_2e	Efficient engine design
FLNG2-EDG3 FLNG2-EDG4 FLNG2-EDG5 FLNG2-EDG6 FLNG2-EDG7	NO_X	LAC 33:III.509	8.80 g/kW-hr	N/A	NSPS Subpart IIII emissions compliance
	CO		3.5 g/kW-hr	N/A	NSPS Subpart IIII emissions compliance
	$PM_{10}/PM_{2.5}$		0.20 g/kW-hr	N/A	NSPS Subpart IIII emissions compliance
	VOC		0.18 g/kW-hr	N/A	NSPS Subpart IIII emissions compliance
	SO_2		sulfur content $\leq$15 ppmw	N/A	Ultra low sulfur diesel as sole fuel
	H_2SO_4		sulfur content $\leq$15 ppmw	N/A	Ultra low sulfur diesel as sole fuel
	GHG		132 tpy per unit	Annual as CO_2e	Efficient engine design
FLNG2-FP1 FLNG2-FP2 FLNG2-FP3 FLNG2-FP4 FLNG2-FP5 FLNG2-FP6	NO_X	LAC 33:III.509	6.40 g/kW-hr	N/A	NSPS Subpart IIII emissions compliance
	CO		3.5 g/kW-hr	N/A	NSPS Subpart IIII emissions compliance
	$PM_{10}/PM_{2.5}$		0.20 g/kW-hr	N/A	NSPS Subpart IIII emissions compliance
	VOC		1.20 g/kW-hr	N/A	NSPS Subpart IIII emissions compliance
	SO_2		sulfur content $\leq$15 ppmw	N/A	Ultra low sulfur diesel as sole fuel
	H_2SO_4		sulfur content $\leq$15 ppmw	N/A	Ultra low sulfur diesel as sole fuel
	GHG		1,166 tpy per unit	Annual as CO_2e	Efficient engine design
FLNG2-FP7	NO_X	LAC 33:III.509	4.00 g/kW-hr	N/A	NSPS Subpart IIII emissions compliance

Emission Point ID	Pollutant	BACT	Limitation	Averaging Period	Description of Control Technology/Work Practice Standard(s)
FLNG2-FP8	CO		3.5 g/kW-hr	N/A	NSPS Subpart IIII emissions compliance
	$PM_{10}/PM_{2.5}$		0.20 g/kW-hr	N/A	NSPS Subpart IIII emissions compliance
	VOC		1.20 g/kW-hr	N/A	NSPS Subpart IIII emissions compliance
	SO_2		sulfur content ≤15 ppmw	N/A	Ultra low sulfur diesel as sole fuel
	H_2SO_4		sulfur content ≤15 ppmw	N/A	Ultra low sulfur diesel as sole fuel
	GHG		512 tpy per unit	Annual as CO_2e	Efficient engine design
FSU-EDG	NO_X	LAC 33:III.509	6.40 g/kW-hr	N/A	NSPS Subpart IIII emissions compliance
	CO		3.5 g/kW-hr	N/A	NSPS Subpart IIII emissions compliance
	$PM_{10}/PM_{2.5}$		0.20 g/kW-hr	N/A	NSPS Subpart IIII emissions compliance
	VOC		1.20 g/kW-hr	N/A	NSPS Subpart IIII emissions compliance
	SO_2		sulfur content ≤15 ppmw	N/A	Ultra low sulfur diesel as sole fuel
	H_2SO_4		sulfur content ≤15 ppmw	N/A	Ultra low sulfur diesel as sole fuel
	GHG		1,270 tpy	Annual as CO_2e	Efficient engine design
FSU-Boiler1 FSU-Boiler2	NO_X	LAC 33:III.509	0.15 lb/MMBtu	3-hour	Good combustion practices
	CO		0.036 lb/MMBtu	3-hour	Good combustion practices
	VOC		0.0025 lb/MMBtu	3-hour	Good combustion practices
	$PM_{10}/PM_{2.5}$		0.0239 lb/MMBtu	3-hour	Good combustion practices
	SO_2		sulfur content ≤0.1 wt%	N/A	Low sulfur fuel
	H_2SO_4		sulfur content ≤0.1 wt%	N/A	Low sulfur fuel
	GHG		3,833 tpy per unit	Annual as CO_2e	Efficient boiler operation
FSU-GCU	NO_X	LAC 33:III.509	0.10 lb/MMBtu	3-hour	Low NO_X Burners
	CO		0.084 lb/MMBtu	3-hour	Good combustion practices
	VOC		0.0055 lb/MMBtu	3-hour	Good combustion practices
	$PM_{10}/PM_{2.5}$		0.0075 lb/MMBtu	3-hour	Good combustion practices
	SO_2		sulfur content ≤20 ppmv	N/A	Natural gas as the sole fuel
	H_2SO_4		sulfur content ≤20 ppmv	N/A	Natural gas as the sole fuel
	GHG		1,797 tpy	Annual as CO_2e	Natural gas as the sole fuel

ATTACHMENT C

THERMAL OXIDIZER AND FLARE CAM PLANS

Thermal Oxidizer Continuous Assurance Monitoring (CAM) Plan

The thermal oxidizers control emissions of volatile organic compounds (VOC) the waste gas produced by the amine stripper column on the gas treatment platform. The thermal oxidizers are of John Zink design and have a control efficiency of 99.9% when operating at 1,600 degrees Fahrenheit (°F). The controlled VOC emission rate of each thermal oxidizer resulting from the acid gas is 0.249 tons per year (tpy). Based upon the control efficiency of 99.9%, the uncontrolled VOC emissions from the acid gas stream would be 249 tpy, which exceeds the Title V major source threshold for VOC emissions of 100 tpy. Therefore, the thermal oxidizers are subject to CAM requirements in accordance with 40 CFR 64.2(a) and must submit a CAM Plan with the initial Title V permit application meeting the applicable requirements under 40 CFR 64.3 and 64.4. This submittal provides the required CAM Plan for the thermal oxidizers.

The proposed CAM Plan is in accordance with Example A.1a from EPA's *Technical Guidance Document: Compliance Assurance Monitoring* (Aug 1998) and CAM Illustration No. 6c from Appendix B (2005) of EPA's guidance document.

<u>CAM Plan Monitoring Approach</u>

In accordance with § 64.4 (a), the owner or operator shall submit to the permitting authority monitoring that satisfies the design requirements in § 64.3. The submission shall include the following information:

1) The indicators to be monitored to satisfy § 64.3(a)(1)-(2);
2) The ranges or designated conditions for such indicators, or the process by which such indicator ranges or designated conditions shall be established;
3) The performance criteria for the monitoring to satisfy § 64.3(b); and
4) If applicable, the indicator ranges and performance criteria for a CEMS, COMS or PEMS pursuant to § 64.3(d).

In accordance with § 64.4 (b), the owner or operator shall submit a justification for the proposed elements of the monitoring. The proposed monitoring is based upon EPA guidance and therefore meets a presumptively acceptable monitoring approach in accordance with § 64.4 (b)(1). Oxidizer temperature is the primary indicator of thermal oxidizer efficiency. The indicator selected was 1,600°F based upon vendor specification or a lower temperature established during a performance test conducted in accordance with 40 CFR § 68. A 3-hour rolling average for the temperature was selected based upon numerous New Source Performance Standards (NSPS) using a three-hour thermal oxidizer temperature for continuous compliance including NSPS Subparts EE, MM, WW, and RRR. The thermal oxidizer combustion chamber temperature will be continuously monitored and data recorded electronically to calculate 3-hour averages.

A second indicator for an annual inspection and tuning of the incinerator burner was selected based upon EPA guidance. Burner inspection verifies equipment integrity and periodic tuning will maintain proper burner operation and efficiency.

The monitoring approach will be validated during an initial performance test to satisfy § 64.4 (c). The testing will be done in accordance with an approved stack test protocol to satisfy § 64.4 (d).

Thermal Oxidizer CAM Plan

CAM Component	Indicator No. 1	Indicator No. 2
I. Indicators	Chamber temperature	Work practice
	The chamber temperature is monitored with a thermocouple.	Inspection and maintenance of the burner
II. Indicator Range	An excursion is defined as temperature readings less than 1600°F or the average temperature during the most recent performance test, whichever is lower. Excursions trigger an inspection, corrective action, and a reporting requirement.	An excursion is defined as failure to perform annual inspection.
III. Performance Criteria A. Data Representativeness	The sensor is located in the oxidizer combustion chamber as an integral part of the incinerator design. The minimum tolerance of the thermocouple is ±4°F or ±0.75%, whichever is greater.	Not applicable
B. Verification of Operational Status	Not applicable	Not applicable
C. QA/QC Practices and Criteria	Accuracy of the thermocouple will be verified by a second, or redundant, thermocouple probe inserted into the oxidizer combustion chamber. This validation check will be conducted annually. The acceptance criterion is ± 32°F (± 2% of Indicator Range).	Not applicable
D. Monitoring Frequency	Measured continuously.	Annual inspection of the burner.
Data Collection Procedure	Recorded continuously in an electronic data acquisition system	Record results of annual inspections.
Averaging Period	3-hour rolling average	Not applicable

Flare Continuous Assurance Monitoring (CAM) Plan

The Project will operate dry flares to control gases vented from relief valves in the cryogenic portions of the liquefaction or LNG storage systems and wet flares to control gases vented from relief valves and the blowdown system of the feed gas treatment rig. The main purpose of the dry and wet flares is to safely handle gas streams during upset conditions, such as the effluent from pressure relief valves and the blowdown system. The flares will control emissions of volatile organic compounds (VOC) at a control efficiency of 99%. The controlled VOC emission rate of each dry flare is 4.07 tons per year (tpy) and each wet flare is 1.61 tpy. Based upon the control efficiency of 99%, the uncontrolled VOC emissions are 407 tpy from each dry flare and 161 tpy from each wet flare, which exceeds the Title V major source threshold for VOC emissions of 100 tpy. Therefore, the dry and wet flares are subject to CAM requirements in accordance with 40 CFR 64.2(a) and must submit a CAM Plan with the initial Title V permit application meeting the applicable requirements under 40 CFR 64.3 and 64.4. As the operation of the dry and wet flares are the same, this submittal provides a single CAM Plan for the flares.

The proposed CAM Plan is in accordance with EPA's *Technical Guidance Document: Compliance Assurance Monitoring* (Aug 1998) and CAM Illustration No. 6c from Appendix B (2005) of EPA's guidance document. EPA's guidance document states flares meeting 40 CFR 60.18 general control device requirements have been determined to be presumptively acceptable for CAM. The required monitoring is limited to the continuous monitoring of the presence of a pilot flame. Because Part 60.18 stipulates design criteria for flares, the lack of specific QA/QC practices is not considered a deficiency for this control device/monitoring combination.

Meeting 40 CFR 60.18 criteria and continuous presence of flame is used for continuous compliance monitoring in accordance with NSPS Subparts VV, DDD, GGG, JJJ, KKK, NNN, QQQ, and RRR.

Therefore, the Project proposes that the dry and wet flares will meet the minimum requirements for flares under 40 CFR 60.18 (c) through (f) and monitor the continuous presence of flame to satisfy CAM requirements. The Project will also conduct an annual inspection of the pilot flame to ensure reliability.

ATTACHMENT D

DETAILED SITE LAYOUT FIGURES

NewFortress energy

Louisiana FLNG Project

Legend

- FLNG1 Air Emission Source
- Project Facility

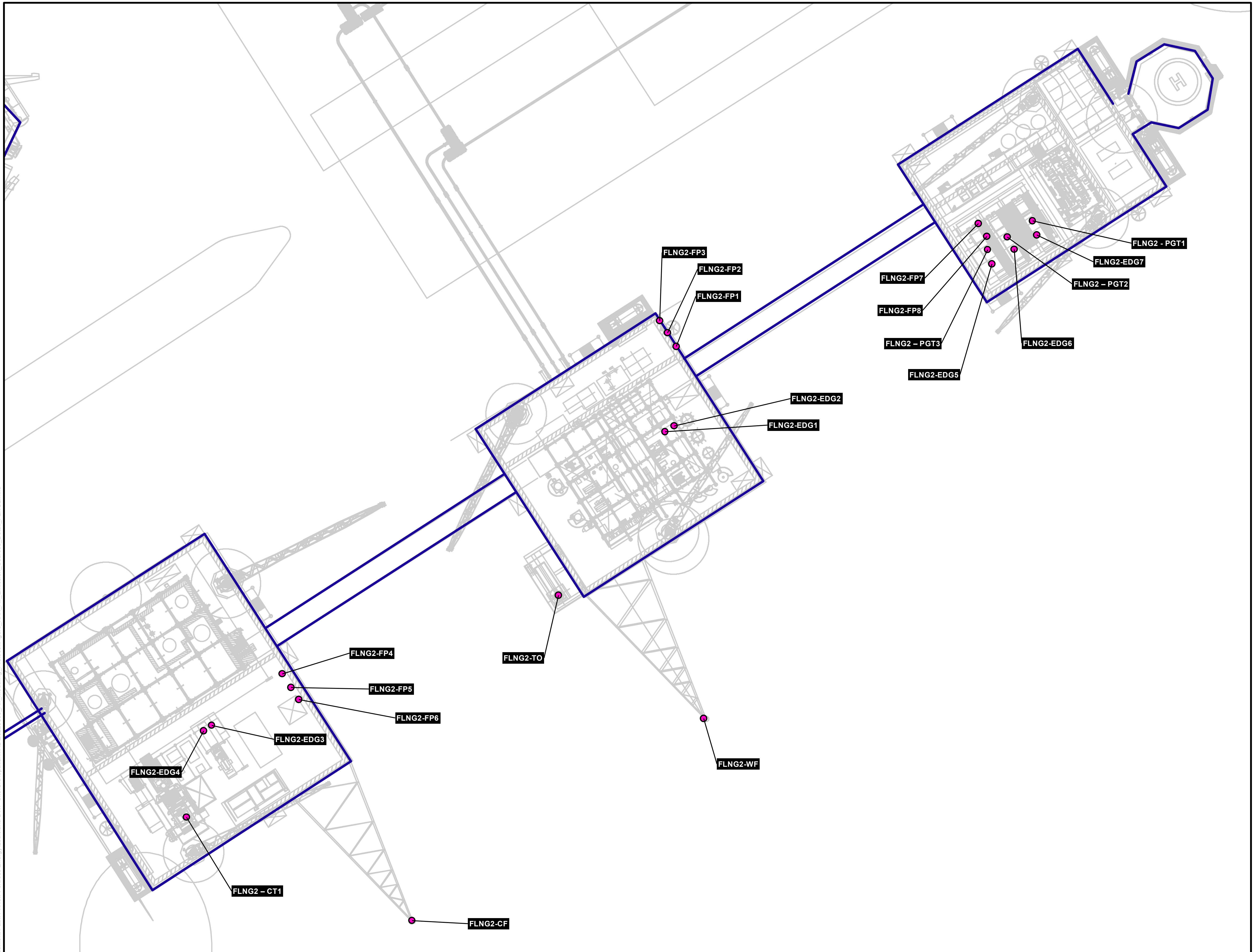
0 25 50 100
Feet

0 10 20 40
Meters

Date Sources: See figure caption for references to data sources used to develop this map.

Coordinate System: NAD 1983 UTM Zone 16N

NOT FOR CONSTRUCTION



NewFortress energy

Louisiana FLNG Project

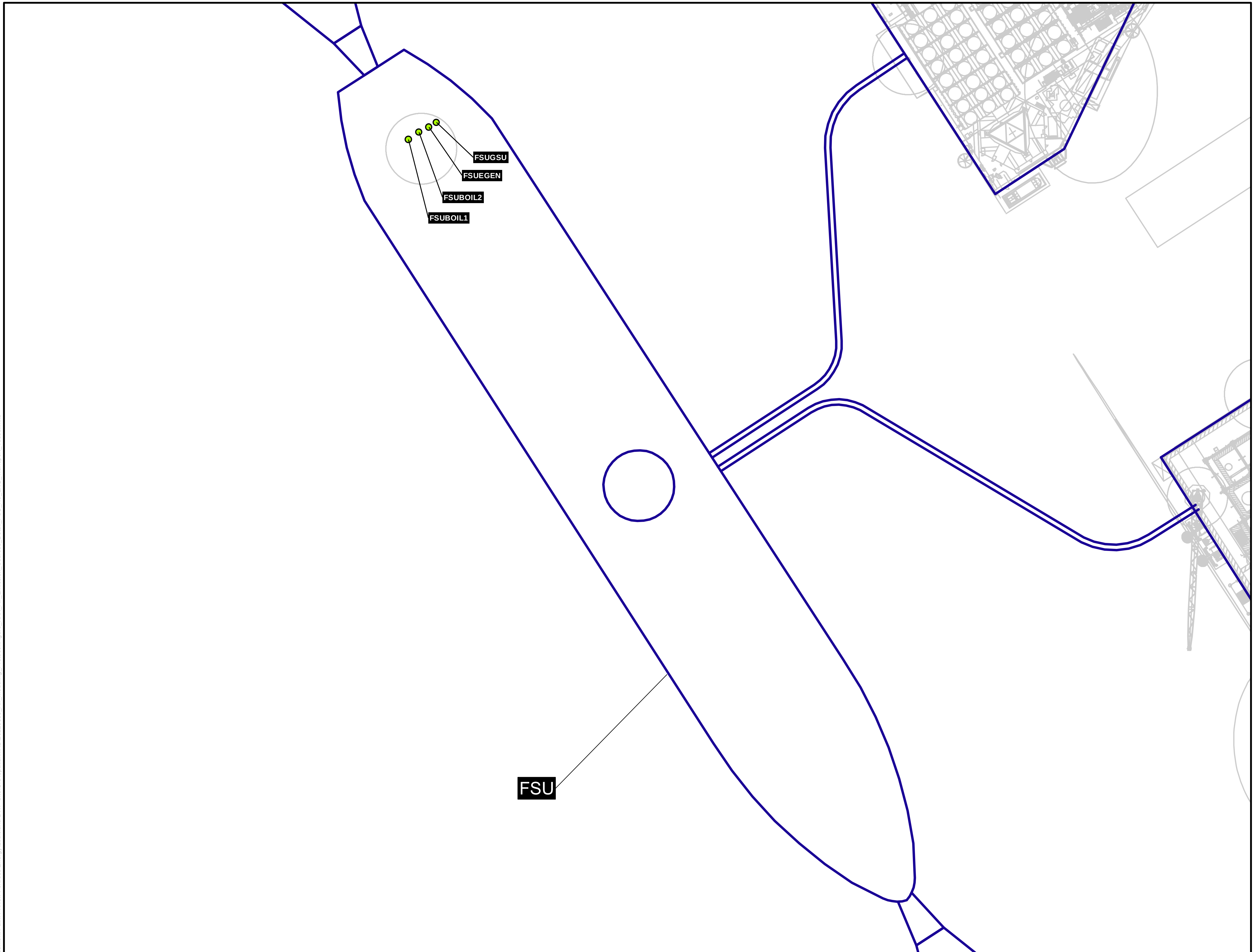
Legend

- FLNG2 Air Emission Source
- Project Facility

Date Sources: See figure caption for references to data sources used to develop this map.

Coordinate System: NAD 1983 UTM Zone 16N

NOT FOR CONSTRUCTION



NewFortress energy

Louisiana FLNG Project

Legend

- FSU Air Emission Source
- Project Facility

0 25 50 100
Feet
0 10 20 40
Meters

Date Sources: See figure caption for references to data sources used to develop this map.

Coordinate System: NAD 1983 UTM Zone 16N

NOT FOR CONSTRUCTION

ATTACHMENT E

DETAILED PROCESS DESCRIPTION

NFE Fast LNG 2 Project

Process Description

Doc. No. N2FE-FLR-100-225-DBD-0004
Rev. 0

22 September 2022

Revision History

Rev	Date	Description	Originator	Reviewer	Approver
0	22-Sept-2022	Issued for Design	HLK	JM / ED	DBP
NFE Approval*					

* NFE Approval as required per the project approval matrix

Modification History

Rev	Sections	Summary of Modifications

Table of Contents

1 INTRODUCTION

This document provides a description of the Process Units provided for NFE Fast LNG 2 Project.

Liquefied Natural Gas (LNG) Liquefaction Facility – FLNG2 – will be installed on three fixed jacket platforms transferring LNG to an adjacent FSU. It is comprised of a single train of gas treating and liquefaction process units along with associated balance of plant (BOP) and other facilities to enable full operation. The liquefaction technology is Chart Industries IPSMR® (Integrated Pre-cooled Single Mixed Refrigerant).

The succeeding sections will present the process description of Unit 110 – Inlet Facilities, Unit 120 – Gas Treating, Unit 130 – Liquefaction, and Unit 146 – BOG Management System. For Utilities, refer to N2FE-FLR-100-225-DBD-0005.

2 PROCESS DESCRIPTION

2.1 UNIT 110 – INLET FACILITIES

Pipeline feed gas is received on the Gas Treatment Platform, which is protected by a High Integrity Pressure Protection System (HIPPS) (110-PK-002). The intent of the HIPPS is to provide an autonomous system, independent of the facility SIS, to protect the facility against pipeline pressures greater than the design pressure of the facility. This results in elimination of a full flow PSV and a significant reduction in the design rate and corresponding height of the Wet Flare. This also effectively separates the design of the facility from the upstream pipeline design, with the exception of the HIPPS itself.

This gas is then sent to the Feed Gas KO Drum (110-V-001). The Feed Gas KO Drum is a vertical cylindrical separator used to disengage entrained liquids originating from upstream processes. Liquid accumulating in the drum is automatically sent to either the Inlet Degassing Drum (110-V-002) or the Inlet Liquids Vaporizer (110-E-002), depending on the water and hydrocarbon content of the collected liquids, on level control. This vessel is not intended to be a slug catcher. A mist eliminator is installed in the vessel to increase efficiency of separation and minimize the carryover of liquids to downstream processes. Pressure drop across the mist eliminator is monitored to determine signs of clogging and potential damage.

The overhead vapor outlet from the drum is sent through the Metering Package (110-PK-001) where it is measured for custody transfer via two (2) metering runs in series in a pay-check configuration. This package includes ultrasonic flow meters, gas analyzer, instrumentation transmitters and flow computers to achieve an accuracy of $\pm$0.3%. The pay/check configuration allows the primary flowmeter (pay), and the other flowmeter (check) acting as the reference meter, to be put in series operation for comparing/checking the accuracy of the primary meter as part of the periodic proving check. The uncertainty is computed as part of the metering system. If either flowmeter requires maintenance, the other meter can be kept in service to allow continued operation.

The flow metering package discharge is heated in the Inlet Gas Heater (110-E-001) to avoid condensation or methane hydrate formation. The inlet gas heater is a shell and tube heat exchanger which utilizes low temperature Hot Oil as the heating medium. Introduction of hot oil is made on flow control, but low or high outlet gas temperature would cause the hot oil flow control valve to adjust as needed. The heated gas leaving the exchanger is controlled to maintain a constant Gas Treatment feed pressure.

The heated gas is then sent to the Gas Treatment Facility to remove components from the feed gas that would make the liquefaction process ineffective and potentially hazardous. During start-up, this stream can be sent to the HP Fuel Gas Mixing drum (143-V-001) to be utilized as high pressure fuel gas and directly into the low pressure fuel gas header.

Liquids from the Feed Gas KO Drum, which may be mostly water, will normally be sent to the Inlet Degassing Drum where any entrained volatile hydrocarbons will be flashed and separated. The vapors from the drum will be sent to the wet flare. The stabilized liquid will be sent to the waste water system on the Gas Treating Platform.

If the liquids contain significant hydrocarbons, the stream can be routed to the Inlet Liquids Vaporizer where they are heated using hot oil and sent to the fuel gas system.

2.2 UNIT 120 – GAS TREATING

The Gas Treating technology is licensed from UOP. The unit is made up of the following areas:

- Mercury Removal
- Acid Gas Removal
- Molecular Sieve Dehydration

2.2.1 Mercury Removal

Feed gas from the Inlet Facility, which may contain mercury, is initially sent to the Mercury Removal Unit. This process unit is intended to protect the mechanical integrity of downstream equipment such as the cryogenic heat exchanger from amalgamation and degradation caused by trace mercury in the feed gas.

The feed gas from the Inlet Facility enters at the bottom of the MRU Coalescer (120-F-006A/B) wherein the bulk of any free liquid present in the gas is removed, prior to the gas passing through the coalescing section. In the coalescing section, smaller free liquid droplets are removed prior to the mercury removal bed. The level of collected liquid is controlled separately in the upper and lower sections using level control valves. Liquids removed from the MRU Coalescers (120-F-006A/B) are sent to the Inlet Liquids Vaporizer (110-E-002) where they are vaporized and sent to the Fuel Gas system.

The gas from the MRU Coalescers is passed through the Feed Heater (120-E-003) where it is heated to ensure that there are no liquids formed downstream.

The gas then flows to the top of the MRU Adsorber (120-V-007) where the elemental mercury is adsorbed by the metal oxide adsorbent bed.

The gas exits at the bottom of the Adsorber and further flows to the MRU Particle Filter (120-F-007) to remove any entrained particulate matter greater than 10 microns prior to sending the treated gas to Acid Gas Removal.

2.2.2 Acid Gas Removal

The Acid Gas Removal Unit (AGRU) removes acid gas components such as CO_2 and H_2S. These components need to be removed to avoid freezing problems in the liquefaction unit and to meet the specifications of the product LNG. The treating system is an amine system using UCARSOL AP 814 Solvent for CO_2 removal to meet the 50 ppmv specification.

Treated gas from the MRU Particle Filter enters the bottom of the Amine Absorber (120-C-001). The treated gas passes through the random packing and is counter-currently contacted with lean UCARSOL solvent to absorb H_2S and CO_2. The random packing provides increased contact between the treated gas and the lean solvent. The treated gas then passes through a wire mesh demister to reduce the lean amine losses at the top of the column. A water wash section at the top of the tower contacts the treated gas with water using trays to remove entrained solvent before passing through another mist eliminator and leaving out the top of the column. Water wash recirculation is provided via the Water Wash Pumps (120-P-006A/B). The rich amine solvent leaves the bottom of the Amine Absorber on level control and is routed to the Rich Solution Flash Drum (120-V-001). The bottom section is also provided with a skimming device and a manual globe valve to skim hydrocarbons and send them to the Amine Recovery Drum (120-V-004).

The wet treated gas exiting the Amine Absorber passes through the Product Gas Cooler (120-A-004A/B) where the gas is cooled and partially condensed. The condensed liquid is knocked out in the Product Gas KO Drum (120-V-003), collected and removed on level control, and then routed to the Rich Solution Flash Drum (120-V-001). The wet treated gas passes through the mist eliminator before being sent to the Molecular Sieve Unit (MSU).

The Rich Solution Flash Drum is a horizontal three-phase separator that degasses the volatile, dissolved hydrocarbons and separates any trace lighter liquid hydrocarbons that may be in the rich amine solvent. The drum is fitted with a mist eliminator to prevent hydrocarbon liquid entrainment in the exit gas prior to sending it to Wet Flare. The collected light hydrocarbon is manually routed to the Amine Recovery Drum prior to sending it to the Amine Sump (120-V-011), while the rich amine is removed on level control and passed through the Lean–Rich Exchanger (120-E-001) where the rich solvent temperature is increased by exchanging heat with the lean solvent leaving the bottom of the Amine Regenerator (120-C-002).

From the Lean-Rich Exchanger, the preheated rich solvent is routed to the top of the Amine Regenerator. The Amine Regenerator is provided with random packing where the solvent is counter-currently contacted with the rising vapor, generated by the Amine Reboiler (120-E-002), to completely strip off the acid gas. The Amine Reboiler supplies the heat to the Amine Regenerator using hot oil as a heat source. The bottom of the Amine Regenerator also provides a surge volume for the amine system.

The lean solvent from the bottom of the Amine Regenerator is sent to the Lean-Rich Exchanger via the LP Lean Solution Pumps (120-P-001A/B). The cooled lean solvent is then sent to the Lean Solution Cooler

(120-A-003A/B) to further cool down before it is recirculated back to the Amine Absorber via the HP Lean Solution Pumps (120-P-002A/B).

A slipstream of the lean solvent is taken downstream of the Lean Solution Cooler and filtered by the Lean Amine Prefilter (120-F-001), Lean Amine Carbon Filter (120-F-002) and Lean Amine Postfilter (120-F-003). The filtered lean solvent is recombined with the lean solvent that bypassed the filters before feeding to the HP Lean Solution Pumps.

Before exiting the Amine Regenerator, the acid gas is contacted with reflux water over the reflux water trays to remove any entrained solvent. The acid gas is partially condensed through the Amine Reflux Condenser (120-A-002) and separated in the Amine Reflux Drum (120-V-002). The reflux liquid is returned to the top of the Amine Regenerator by the Amine Reflux Pumps (120-P-005A/B) as reflux water. The acid gas exiting from the top of the Amine Reflux Drum, together with the flash gas from the Rich Solution Flash Drum, are sent to the Wet Flare via an eductor using fuel gas as motive fluid. The eductor, Amine Reflux Drum Ejector (120-Y-001) increases the pressure of the acid gas prior to sending it to the wet flare. The mixing of fuel gas with the acid gas increases the heating value of the acid gas stream to 300 MMBTU/SCF to meet the required destruction efficiency in the flare.

The AGRU is also provided with an Antifoam Injection System (120-PK-001), makeup water system and a dedicated closed drain system. Makeup demineralized water is sent to the Amine Absorber from the Water Break Tank (120-V-008) via the Water Makeup Pumps (120-P-009A/B). The Amine Closed Drain system includes an Amine Sump, Amine Sump Pump (120-P-003A/B) and Solution Filter (120-F-004). The recovered amine is then recirculated back to the Amine Regenerator during unit filling.

2.2.3 Molecular Sieve Unit

Treated gas from the AGRU is saturated with water as it has been scrubbed with an amine/water solution. Wet treated gas is then sent to the Dehydration Unit to remove excess water and to achieve a low water dew point (0.1 ppmv) to avoid freezing in the liquefaction unit.

Product Gas from the AGRU flows through the Inlet Filter Coalescer (120-F-005) to separate any entrained liquid originating from the upstream processes. Vapor exiting the coalescer will be fed into Adsorbers (120-V-005A/B/C) and pass downward in adsorption mode. Under normal operation, two (2) of the three (3) Adsorbers remove water from the wet treated gas while the third Adsorber progresses through a series of steps for thermal regeneration to desorb water. Each adsorber vessel contains UOP Molecular Sieve adsorbent to remove water from the gas.

The treated gas meeting the product specification exits the bottom of the Adsorber and passes through Particle Filters (120-F-008A/B) before flowing to the Liquefaction Facility. The filters are designed to remove entrained particulate matter greater than 10 microns.

There are three cycles during Regeneration mode: heating, cooling, and standby. During the heating cycle, a slipstream of dry treated gas taken from downstream of the Particle Filters is heated with hot oil via the Regeneration Gas Hot Oil Heater (120-E-005A/B). The heated gas then enters the bottom of the Adsorber to regenerate the molecular sieve bed and exits the top of the Adsorber. It will pass through the

Regeneration Gas Cooler (120-A-001) to cool down prior to going to the Regeneration Gas KO Drum (120-V-006), where condensed water is separated. The vapor is recirculated back to the AGRU through the Regeneration Gas Compressor (120-K-001) while the condensed water is sent to the Regeneration Water Filter (120-F-009) to remove entrained particulate matter greater than 10 microns. The level of collected liquid is controlled using level control valves and any liquid drained from the KO drum is sent back to the Rich Solution Flash Drum.

During the cooling cycle, the Regeneration Gas Hot Oil Heater is by-passed, and the regeneration gas flows directly upward through the Adsorber. Regeneration gas can be temporarily routed to the Wet Flare in case the Regeneration Gas Compressor is tripped.

Once the heating and cooling cycle is complete, the regenerated bed will go into standby mode. The pressure is maintained in the regenerated bed while the regeneration gas is bypassed around the adsorbers to continue to feed the Regeneration Gas Compressor.

2.2.4 AGRU Solvent Storage and Transfer

Pure UCARSOL AP-814 solvent is stored in the Amine Solvent Drum (120-V-010). This vessel is provided with nitrogen blanketing to prevent degradation of the amine. This pure amine is pumped out by the Amine Solvent Pump (120-P-013A/B) as makeup amine to the AGRU. It is mixed with demineralized water in the correct ratio online before transfer into the AGRU amine network.

The Solution Storage Tank (120-T-001) is used as storage when the unit is emptied of amine inventory during maintenance. This tank is provided with nitrogen blanketing to prevent degradation of the solvent. The solution is returned to the amine network of the AGRU using the Solution Transfer pump (120-P-008A/B). Provisions to supply fresh amine and demineralized water are also provided for the Solution Storage Tanks for when larger quantities of amine solution are needed, such as during initial fill of the AGRU.

2.3 UNIT 130 – LIQUEFACTION

The Liquefaction Unit 130 utilizes Chart's IPSMR® technology, which is an integrated pre-cooled single mixed refrigerant (IPSMR) process. The unit includes further gas treating in the Heavy Hydrocarbon Removal Cold Box and liquefaction of the natural gas in the Liquefaction Cold Box. The Defrost Gas System is also included in this unit.

2.3.1 Heavy Hydrocarbon Removal

After acid gas, water and mercury are removed in the Gas treatment facility, the feed gas enters the Heavy Hydrocarbon Removal section. This unit will remove hydrocarbons equivalent or heavier than C5+ such as benzene and other aromatics. Removing these components will achieve the required LNG product quality and prevent freezing in downstream equipment.

The removal process involves utilization of a multi-pass Heavies Removal Exchanger (130-E-001) where the treated gas is precooled through the exchanger. A portion of the feed gas is routed through a control valve to the bottom of the Heavies Removal Scrub Column (130-C-001) as stripping gas. The remainder is sent to exchanger pass A2 where it is further cooled and sent to the Heavies Feed Separator Drum (130-V-002). The vapor from the separator drum is sent to exchanger pass A3 where the feed gas is cooled and partially condensed before it is routed through a control valve to the Heavies Removal Scrub Column main feed.

The Heavies Removal Scrub Column consists of two (2) I-ring packed bed sections with associated internal components. Reflux for the Heavies Removal Scrub Column is generated by partially condensing the vapor draw from the top bed of the Heavies Removal Scrub Column in exchanger pass B. The liquid stream is returned as reflux to the Heavies Removal Scrub Column via the Heavies Removal Reflux Pumps (130-P-001A/B). The Heavies Removal Reflux Pumps are located on a skid outside of the Heavies Removal Cold Box. The vapor product from the Reflux Drum (130-V-001) is passed through a JT valve and enters exchanger pass C to provide cooling to the incoming feed gas before being diverted to the Feed Gas Booster Compressor (130-K-002).

The Natural Gas Liquids collected from the scrub column bottoms is pressurized by the Scrub Column Bottoms Pumps (130-P-003A/B), preheated by the Scrub Column Bottoms Preheater (130-E-005), then vaporized in the Scrub Column Bottoms Vaporizer (130-E-003) to be used in the HP fuel gas system as fuel gas. Due to the low flow, low MDMT, low NPSH, and high head, the pumps are vertical canned pumps.

The Scrub Column Bottoms Preheater (130-E-005) is a hairpin cross exchanger which preheats the cold scrub column bottoms to an intermediate temperature via the hot vaporized scrub column bottoms. The intent of this exchanger is to prevent hot oil from freezing in the event the hot oil is blocked in on the vaporizer.

The Scrub Column Bottoms Vaporizer (130-E-003) is a hairpin cross exchanger which utilizes high temperature hot oil as heating medium. Introduction of hot oil is made through flow control. Low or high outlet gas temperature and exchanger liquid level adjust the hot oil flow control set point as needed. For certain cases, the vaporized gas can be recycled back to the Scrub Column for additional stripping/heating.

LNG production significantly decreases with low feed pressure to the liquefaction cold box, therefore, the pressure is boosted with the electric-motor driven Feed Gas Booster Compressor (130-K-002) and cooled via Feed Gas Booster Compressor Discharge Cooler (130-A-001A/B/C/D) and sent to the Liquefaction Exchanger (130-E-002A-F) on the Liquefaction Platform.

The four stage compression of the Feed Gas Booster Compressor is capacity controlled by a suction throttle valve and inlet guide vanes. No suction scrubber is provided for liquid knockout since gas has been treated prior to compression and no liquid formation is expected. Anti-surge protection is provided downstream of the aftercooler and recycles back to the suction of the compressor. If the compressor is out of service, a bypass valve can be utilized, however, at a reduced LNG capacity.

The Heavies Removal Exchanger, Heavies Removal Reflux Drum, Heavies Removal Scrub Column, and Feed Separator Drum are installed in the Heavies Removal Cold Box (130-CB-001), a structure filled with perlite insulation and provided with a dry nitrogen purge, that encloses key cold side equipment in the process.

2.3.2 Liquefaction

The air-cooled vapor from the Feed Gas Booster Compressor Discharge Cooler is fed to pass A of the Liquefaction Exchanger (130-E-002A-F). As the vapor traverses the liquefaction exchanger, the fluid is de-superheated, condensed, and subcooled using different levels of Mixed Refrigerant (MR) introduced at different exchanger passes. After leaving pass A, the pressure is let down and the fluid is returned to pass C of the Liquefaction Exchanger, where it is further cooled then routed to the End Flash Drum (130-V-009).

The End Flash Drum receives the LNG from the Liquefaction Cold Box and stabilizes the LNG to prevent flashing in the storage tanks on the Floating Storage Unit (FSU). The vapor stream from the drum is sent to the Boil-off Gas (BOG), BOG Management System, and the liquid product stream is pumped to the FSU via the cryogenic End Flash Pumps (130-P-003A/B/C). LNG is also routed to the BOG Desuperheater (146-Y-001) to control the BOG temperature to the BOG Compressor (146-K-001). Due to the cryogenic temperatures, the drum, piping, and pumps are stainless steel.

The Liquefaction Exchanger is a Brazed Aluminum Heat Exchanger licensed, designed, and supplied by Chart to provide the cooling duty of the main Liquefaction Unit. The system utilizes six (6) exchangers installed in parallel with each other and each has thirteen (13) passes (A, B, C, D1-L, D1-V, D2-L, D2-V, D3-L, D3-V, E, F, G, and H).

Duty for the liquefaction process is provided by the heating and vaporization of three refrigerant grades (warm, mid, and cold) fed progressively to colder points in the Liquefaction Exchanger (130-E-002A-F). MR is comprised of a mixture of methane, ethane, propane, i-pentane, and nitrogen. The preparation and separation of these refrigerant streams begins with the MR Suction Drum (130-V-006) where fresh make-up streams are introduced into the loop as necessary, and the refrigerant mixture is compressed by the MR Compressor (130-K-001). The MR Compressor is a two stage compressor mounted on a single shaft driven by an aeroderivative gas turbine LM6000 PF+ (130-KT-001).

MR discharge pressure is controlled by compressor speed variation. The pressure profile through the closed loop circuit is critical to achieve proper liquid/vapor ratios after each compression stage. From the MR Suction Drum, the gas is routed to first stage of compression, 130-K-001-1.

Medium Pressure MR is partially condensed in the MR Compressor 1st Section Cooler (130-A-002A-H) and separated in the MR Interstage Drum (130-V-007). The comparatively heavy liquid from the drum is sent to pass B of the Liquefaction Exchanger (130-E-002A-F) for subcooling. Vapor from the Interstage Drum is further compressed in the MR Compressor 2nd Section (130-K-001-2) and desuperheated using MR Compressor Desuperheater (130-A-003A/B). Discharge of the desuperheater is sent to the MR Compressor 2nd Section Condenser (130-A-004A-F) to produce a two-phase fluid to be separated in the MR Accumulator (130-V-008). The liquid and disengaged vapor from the accumulator is respectively sent to pass E and F of the Liquefaction Exchanger.

Individual anti-surge valves are provided with recycle lines for protection of the two sections of the compressor. First anti-surge protection is provided downstream of the 1st Section Cooler and recycles back to the suction drum of the compressor. Second anti-surge protection is provided downstream of the desuperheater and recycles back to the interstage drum. HIPPS is provided on the fuel gas supply to the turbine being initiated with 2oo3 voting of the high-high pressure initiators on the MR Compressor intermediate and discharge stages. HIPPS on the fuel gas was added to reduce the pressure relief to flare, by ensuring loss of turbine power.

A complex control loop controls the MR Compressor 1st and 2nd Section Coolers to maintain the balance between the liquid levels of the MR Interstage Drum (130-V-007) and MR Accumulator (130-V-008). The various refrigerant grades utilized in the liquefaction process are produced using this complex control loop in combination with each of the MR fluids using strategically controlled JT valves discharging into the Cold Standpipe (130-SP-0001), Mid Standpipe (130-SP-0002) and Warm Standpipe (130-SP-0003). The standpipes and Liquefaction Exchanger are installed in the Liquefaction Cold Box (130-CB-002) which is filled with perlite insulation and provided with a dry nitrogen purge.

The low-pressure refrigerant streams generated from the cold, mid and warm standpipes are fed back to passes D1, D2 and D3 of the Liquefaction Exchanger (130-E-002) respectively. These fluids combine into one (1) stream inside the Exchanger and exit the warm end of the exchanger as vapor, approaching the exchanger feed gas temperature. The combined stream returns to the MR Suction Drum (130-V-006) to complete the “refrigerant cycle” of the liquefaction process.

2.3.3 Defrost Gas

During startup, entrained fluids in the system which can cause freezing problems are removed by hot gas stripping. Dry gas from the Gas Treating Unit is heated using hot oil in the Defrost Gas Heater (130-E-004). The resulting defrost gas is routed to different sections of the Liquefaction unit to vaporize liquids that have accumulated in the system. Once completed, cooling of the Liquefaction Exchanger is initiated using a bypass valve to divert a small part of the MR Cold Separator (130-V-003) liquid stream. The valve pulls liquid from pass H of the Liquefaction Exchanger (130-E-002) to feed directly into the Cold Standpipe inlet line. This enables the process to be cooled from the bottom up and is especially useful in providing fine control on temperature rates of change during startup.

2.4 UNIT 146 – BOG MANAGEMENT

Boil-off Gas is produced from the heat ingress to cryogenic service equipment and vapor displacement in the FSU and ship loading. Vapor originating from the End Flash Drum (130-V-009) and BOG from FSU operations is sent to the BOG Compressor Suction Drum (146-V-001).

Vapor outlet of the BOG Compressor Suction KO Drum (146-V-001) is sent to multistage compression in the BOG Compressor (146-K-001). The primary function of the BOG Compressor Suction Drum is to prevent any liquid from entering the BOG Compressor. A demister pad is installed in the vessel to increase efficiency of separation and further prevent liquid carry-over. Demister pressure drop is monitored to determine signs of clogging and potential damage. Due to the cryogenic temperatures, the drum is stainless steel.

The selected compressor requires a constant recycle for all cases to maintain desired volumetric flowrates. The recycle takes from downstream of the aftercooler and recycles back to the suction drum increasing the combined BOG temperature. To chill and prevent high temperature flow of the gas sent to the BOG

Compressor, the BOG Desuperheater (146-Y-001) will utilize LNG from the End Flash Pumps discharge to maintain the desired temperature.

The liquid accumulated in the BOG Compressor Suction Drum can be routed to either the End Flash drum or to the flare system. When operating with lean feed gas, liquid drop out is expected to be minimal. In this mode, any liquid is drained into the 30" pipe then pressurized into the flare system. When operating with rich gas, liquid drop out is expected to be continuous. As such, liquids are pumped via low flow cryogenic BOG Suction Drum Pump (146-P-001A/B) back to the End Flash Drum. Line up of the valves is done in the field.

The main function of the BOG Compressor, 146-K-001, is to compress BOG to the operating pressure of the HP Fuel Gas System. The compressor is a six-stage machine and is capacity controlled by inlet guide vanes. The six stages of compression are mounted on a single shaft. Interstage cooling takes place between stages 4 and 5. Individual anti-surge valves are provided with recycle lines for protection of the 2 sections of the compressor. Section 1 comprises of stages 1-4 and section 2 includes stages 5-6. First anti-surge protection is provided downstream of the interstage cooler and recycles back to the suction of the compressor. Second anti-surge protection is provided downstream of the aftercooler and recycles back to the suction of the stage 5. A total recycle from downstream of the aftercooler to the suction drum is provided for the compressor capacity control.

A slipstream from the BOG compressor interstage Cooler (146-A-001) is to be utilized as Low Pressure Fuel Gas. The discharge of the final compression stage is cooled down via BOG Compressor Aftercooler (146-A-002) to generate High Pressure Fuel Gas. The outlet temperature is modulated to prevent overcooling BOG which reduces the available superheat of the fuel gas required by the gas turbines for the MR Compressor and Power Generation. The target superheat of the vapor is 28°C above hydrocarbon dew point on the combined HP fuel gas stream.

There are two modes of operation of the facility, holding mode and loading mode.

- Holding mode is defined as facility operation without LNG being loaded from the FSU to the LNG Carrier (LNGC). LNG produced is being stored in the FSU during this mode of operation.
- Loading mode is defined as facility operation with LNG being loaded from the FSU to the LNGC. LNG is still produced during this mode and stored in the FSU.

During Loading Mode, the higher amount of BOG reduces the amount of make-up to the fuel gas system and the amount of compressor recycle to the BOG suction (and LNG needed for desuperheating) is decreased.

NFE Fast LNG 2 Project

UTILITIES DESCRIPTION

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Rev. 0

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Rev	Date	Description	Originator	Reviewer	Approver
0	21-Nov-2022	Issued for Design	MM / PNS / HLK	ED / JEM	DBP
NFE Approval*					

* NFE Approval as required per the project approval matrix

Modification History

Rev	Sections	Summary of Modifications

TABLE OF CONTENTS

1 INTRODUCTION

This document provides a description of the Utility Systems provided for NFE Fast LNG 2 Project.

Liquefied Natural Gas (LNG) Liquefaction Facility – FLNG2 – will be installed on three fixed jacket platforms transferring LNG to an adjacent FSU. It is comprised of a single train of gas treating and liquefaction process units along with associated balance of plant (BOP) and other facilities to enable full operation. The liquefaction technology is Chart Industries IPSMR® (Integrated Pre-cooled Single Mixed Refrigerant).

Balance of Plant considers the following Utility Systems to support the facility:

- Unit 141– Power Generation System, including main power and emergency power generation and their supporting facilities.
- Unit 142– Diesel Fuel System
- Unit 143– Fuel Gas System
- Unit 144– Instrument Air System
- Unit 145– Nitrogen System
- Unit 147– Water Systems (Raw, Utility, Potable and De-mineralized Water)
- Unit 151– Hot Oil System
- Unit 152– Refrigerant Storage System
- Unit 153– Fire Protection System
- Unit 154– Flare System
- Unit 155– Waste Water Treatment, Sewage Treatment, and Drainage and Effluent Treatment

For Gas Treating, Liquefaction Process, and BOG Handling process description, refer to N2FE-FLR-100-225-DBD-0004.

2 OVERALL UTILITIES DESCRIPTION

2.1 UNIT 141 – MAIN POWER GENERATION SYSTEM

NFE Fast LNG 2 main power is provided by three SGT-400 Siemens Gas Turbine Power Generators (141-PK-001A/B/C). High pressure (HP) fuel gas is supplied from the Fuel Gas Mixing Drum. Each turbine is iso rated for 12.87 MWe and are all normally in operation to provide total Facility normal electrical load of approximately 26 MW. The process facility power system is integrated with the platform main and emergency power systems.

The hot exhaust gas from each turbine will be channeled through a Waste Heat Recovery Unit (141-E-001A/B/C) to heat Therminol 72 which serves as a heating medium for several heat exchangers in the facility.

Essential emergency power is provided for blackstart and emergency using five Warren Cat 3512-C diesel fueled generators (141-PK-002A/B/C and 141-E-004A/B), each is rated for 1730 MW. Three units will be placed in the Utilities Platform and two units in the Liquefaction platform. Gas Treating will be primarily fed from Liquefaction units, with switching capability to supply from the Utilities Platform units in case of loss of feeder from the Liquefaction platform units. Each generator unit will include a 24-hr day tank that will be supplied by the Raw Diesel supply and Treatment unit.

The hot exhaust gas from the diesel driven turbines is individually channeled through a silencer for noise reduction and routed to atmosphere at a safe location.

2.2 UNIT 142 – DIESEL FUEL SYSTEM

Diesel will be supplied periodically via transport boats to the facility through a dedicated loading station in the Utilities Platform, and it is filtered and stored in the Raw Diesel Tank. A full tank is adequate for seven (7) day supply for one diesel engine and three (3) day supply for two firewater pumps.

Diesel is transferred by the Raw diesel Pump through the Diesel Treatment Unit for removal of water and fine particles prior to supplying to the end users. In addition to the Essential Power Generators, diesel will be supplied to the main Fire Water Pumps in all three platforms. Each Firewater pump package will include an 18-hr day tank. Day tanks will fill from the header on level control

During normal operation, diesel will be available for emergency use in case of primary power failure, and for the periodic testing of equipment.

The piping system around the Raw Diesel Tank and pumps are designed to allow transfer of diesel to and from the loading station to allow for tank de-inventory.

2.3 UNIT 143 – FUEL GAS SYSTEM

The fuel gas system is designed for continuous operation of the major HP fuel gas consumers. The HP fuel gas is mixed in the Fuel Gas Mixing Drum (143-V-001), and is made up from the following streams:

- Boil Off Gas (BOG), flashing off from the LNG End Flash Vessel (130-V-009) and the Floating Storage Unit (FSU) compressed by the BOG Compressor (146-K-001)
- Vaporized Heavies Removal Scrub Column (130-C-001) bottoms
- Dry make up fuel gas from the Gas Treating Unit
- Wet make up fuel gas from Inlet Facilities (during start-up only)

All vaporized scrub column bottoms from the Heavy Hydrocarbon Removal section are conditioned to be suitable fuel gas. The gas from the BOG Compressor system serves as the swing supply on top of the vaporized scrub column bottoms. Any shortfall in HP Fuel Gas is made up by dry fuel gas from the Gas Treating facility. During start-up, wet feed gas from the Inlet Facilities is used as fuel gas, until dry treated gas is available.

The contribution of each source to the total fuel gas demand changes as the operating mode changes from Holding to Loading. During operation of the facility, the LNG is loaded continuously onto the Floating

Storage Unit (FSU). Typically, once a week (more frequently for 2 train operation) for approximately 20 hours, the FSU loads the stored LNG to the LNG Carrier (LNGC). This period is considered “loading mode.” Periods when the FSU is not loading LNG to the LNGC are considered “holding mode.” More BOG is generated during loading mode than during holding mode. The higher amount of BOG reduces the amount of make-up required to the fuel gas system.

The HP fuel gas distribution header pressure on the Liquefaction Platform is monitored and set by split-range control of flow from the Scrub Column Bottoms Vaporizer and the BOG compressor. The compressed BOG has two valves geared for low flow and high flow operating cases. During normal operation, the high flow valve is used. During start-up, when fuel gas demand is low, and BOG supply is limited, the low flow valve is used. Both valves should not be in operation at the same time.

If fuel gas demand is higher than the scrub column and BOG compressor can supply, fuel gas pressure is maintained by flowing make-up gas from either dry treated gas or wet feed gas. If fuel gas demand is lower than the scrub column and BOG compressor flow, excess BOG is recycled back to the suction of the Feed Gas Booster Compressor (130-K-002) under pressure control.

The HP fuel gas is further let down in pressure via a pressure control valve to supply fuel gas to other users on the Gas Treating and Utilities platforms

HP fuel gas is supplied to the following users:

- SGT Power Generation Gas Turbines (let down to 29 – 22 bara)
- Mixed Refrigerant (MR) Compressor Gas Turbine (at high pressure, 48.7 bara)

The gas turbines are sensitive to sudden changes in the fuel gas Wobbe Index; hence the Fuel Gas Mixing Drum is provided to limit the rate of change of Wobbe Index as the operation swings between Holding and Loading modes to a maximum of 1% per minute. The Wobbe Index is monitored on the vapor leaving the Fuel Gas Mixing Drum via a Wobbe Index analyzer.

Low pressure (LP) fuel gas is required in the Gas Treating Platform and the Liquefaction Platform for the following users:

- Gas Treating Eductor (Amine Reflux Drum Ejector)
- Purge gas for the flare and closed drain collection headers.
- Pilot and ignition gas for the Wet and Dry Flare packages.

The LP fuel gas supply to the eductor on the Gas Treating Platform is supplied from the high pressure treated gas line and is provided with a dedicated HP to LP letdown station.

The LP fuel gas supply to the wet flare system on the Gas Treating Platform is primarily supplied from the fuel gas header, with back-up from the dry natural gas makeup line. Each line is provided with an HP to LP letdown station.

The LP fuel gas supply to the dry flare system in the Liquefaction Platform is primarily supplied from the BOG compressor interstage gas with back-up from the fuel gas header. Each line is provided with an HP to LP letdown station. All LP fuel gas users will rely on wet feed gas sent through the electric fuel gas heater and mixing drum during black start.

The fuel gas system equipment is located on the Liquefaction Platform. The Fuel Gas Start-up Heater (143-H-001) is an electric heater designed to superheat gas letdown from the high pressure natural gas header and should only be required during start-up. The fuel gas heater discharge temperature shall be maintained to achieve the required degree of superheat for the gas turbines. During black start of the facility, a tie-in upstream of the Mercury Removal Unit supplies wet feed gas to the HP Fuel Gas Mixing Drum to be used as fuel gas.

The mixed fuel gas temperature at the distribution header is maintained with 28°C superheat to prevent combustion turbine damage due to flashback. The vaporized scrub column bottoms stream lowers the amount of superheat in the mixed fuel gas stream. To maintain the desired 28°C superheat, the compressed BOG source temperature is raised by control valves that control the amount of the hot BOG compressor discharge that bypasses the BOG Compressor After Cooler (146-A-002). The operator manually adjusts the fuel gas temperature set point considering dew point variations to be within the required superheat range. The degree of superheat is calculated for operator monitoring.

Any liquids accumulation in the HP Fuel Gas Mixing Drum are routed to the dry gas flare header via level control.

2.4 UNIT 144 – INSTRUMENT AIR SYSTEM

The purpose of the instrument air unit is to produce dry compressed air for the nitrogen PSA unit, instruments, purging, pneumatic tools, and other utility needs.

The capacity of the instrument air system is based on the maximum rate for all users. Peak rate usage of all users is non-coincidental and occurs intermittently, therefore does not set the capacity of the system. Refer to the Utility Summary (N2FE-FLR-100-225-SUM-0001) for detailed consumption rates.

The unit provides four (4 x 33%) oil free, electric driven screw compressors, (144-K-001A/B/C/D), three running continuously in a two lead/ one lag arrangement, sending wet compressed air at approximately 10.5 bara air to the air dryer packages.

Three (3 x 50%) self-regenerating, externally heated, desiccant air dryer packages (144-PK-001A/B/C) are designed to achieve a water dew point (ISO 8573-1 Class 2.2.2) of -66°C as set per the nitrogen refrigerant quality requirement. Dew point analyzers are provided at each dryer unit outlet instrument air line and set to alarm operators to switchover to standby dryer if the dewpoint is not met. The dry air is then sent to the Instrument Air Receivers (144-V-001A/B/C) sized to hold a total surge capacity of 15 minute between 9 bara and 5 bara. The instrument air header supplies instrument air to all three platforms.

Instrument air header pressure is monitored at the outlet of the Instrument Air Receivers and is sent to the lead compressor unit controller, acting as a master controller, to maintain the air header pressure and dew point.

The Instrument Air system also provides air to utility stations across the facility. On low air pressure, supply to the utility stations is cut-off to preserve air for instrumentation.

2.5 UNIT 145 – NITROGEN SYSTEM

The Nitrogen Pressure Swing Adsorption (PSA) package (145-PK-001) supplies nitrogen across the facility. The primary purpose of the unit is to produce high-purity, refrigerant grade gaseous nitrogen required for the Liquefaction refrigerant. The nitrogen will also be used for normal, continuous usage such as purging, vessel blanketing, compressor seal gas, as well as intermittent usages such as peak purges and pressurizing medium. The capacity of the nitrogen is based on normal rate for all the users plus 10% margin. Peak rate usage of all users in non-coincidental and occurs intermittently, therefore does not set the capacity of the system. Supply pressure of nitrogen to the distribution header will be regulated by a pressure controller at the outlet of the receiver such that it meets or exceeds the minimum pressure of 6.5 bara at the MR Compressor skid. Refer to the Utility Summary (N2FE-FLR-100-225-SUM-0001) for detailed consumption rates.

2.6 UNIT 147 – WATER SYSTEMS

The Raw Water System provides seawater as the primary source for water treatment and conditioning systems to meet the facility requirements. Three types of water are required by the facility: utility water, potable water, and demineralized water.

2.6.1 RAW WATER

The two Raw Water Pumps (147-P-001A/B) are located in individual caissons on the Utilities Platform to provide seawater to the following users:

- Feed water to the Desalination Package in the utility water system for all facility desalinated water users
- Feed water to the Hypochlorite Generation Package
- Raw water supply to the Sanitary Treatment System

The raw water pumps are submersible and designed to lift seawater approximately 30m above mean sea level to the cellar deck. Raw Water Pumps (2 x 100%) interlock to auto start standby pump upon failure of operating pump. Raw Water Pump Filters (147-F-001A/B) remove sand and solids from the seawater.

The Hypochlorite Generation Package (147-PK-007) takes raw water from the Raw Water Pump discharge and generates a hypochlorite solution for injection into the raw water pump caissons, firewater pump caissons, and firewater mains through the jockey pumps to control biological growth in the caissons and piping.

2.6.2 UTILITY WATER

Raw water feeds the Desalination Package (147-PK-002) to generate desalinated (utility) water to meet the maximum demand for potable water. The system will pass the raw seawater through additional filtration, including media filter beds, followed by the Seawater Reverse Osmosis (SWRO) unit to produce desalinated water suitable for plant use. Utility water is stored in two (2) Utility Water Tanks (147-T-003A/B), each with a working capacity for two hours of one firewater jockey pump operation. The three (3 x 50%) Utility Water Pumps (147-P-006A/B/C) transfer utility water to each of the platforms to be used for the firewater jockey pumps, utility stations, and supply for demineralized water package. Also, the Utility water pumps provide feed to the potable water tanks.

Utility water tank levels are maintained to ensure adequate utility water is available for living quarter sprinkler system and jockey pump, when required.

Provisions are provided to fill the Utility Water Tanks from the loading station.

2.6.3 POTABLE WATER

The potable water system is designed to produce and /or receive, store, and distribute potable water to users throughout the facility. Potable water is supplied to the following users:

- Eyewash and safety showers
- Accommodations for personnel use.
- For personnel use at the muster rooms, LER rooms.

Desalinated utility water is chlorinated then stored in Potable Water Tanks 147-T-002A/B sized for four days of storage for accommodations maximum rate. From the Potable Water Storage Tanks, the three (3 x 50%) Potable Water Pumps (147-P-002A/B/C) feed the water on demand to the three (3 x 50%) UV Sterilization Package (147-PK-005A/B/C) and then distribute it to the living quarters, LERs, muster rooms, and eye wash/safety showers on all platforms. Maximum rate in accommodations is based on 0.4 m^3 (100 gallons) for 120 people averaged over 24 hours.

Additional three dedicated potable water tanks are provided in the accommodations which will provide an additional four days of capacity.

2.6.4 DEMINERALIZED WATER

Demineralized water is mainly required on the Gas Treating Platform for amine solvent solution preparation, makeup water for the Amine Absorber and Amine Reflux Drum, and other intermittent activities such as turbine washing and filter cleaning. A Demineralized Water Conditioning Package (147-PK-001) is provided on the Gas Treating Platform. It is supplied with utility water from the utility water distribution header.

A Demineralized Water Tank (147-T-001) provides approximately 18 hours hold up of pump rated capacity. The demineralized water is pumped to the distribution header in the Gas Treating Platform via

Demineralized Water Pump (147-P-003A/B). For the initial preparation of the amine solvent solution at startup, the pumps will operate in parallel to deliver the solvent volume of water within 24 hours. Normal operation requires one pump to operate continuously with continuous recirculation. A liquid level signal from the tank is be provided to the 147-PK-001 PLC for start/stop batch control. A separate level signal is interlocked with the pump controls to stop at low-low liquid level. The tank pressure is maintained by a set of back pressure regulators for nitrogen blanket for tank in-breathing and a vent to atmosphere for tank out-breathing.

Other demineralized water requirement is limited to gas turbine wash of the Power Generation Gas Turbines and the MR Compressor gas turbine and will be provided by totes as needed. Startup demineralized water requirements for the amine systems unit flushing exceeds the facility storage capacity and will need to be sourced externally.

2.7 UNIT 151 – HOT OIL SYSTEM

A closed hot oil circuit is available to provide the heating medium for several heat exchangers in the Inlet facilities and Gas Treating.

The circuit mainly consists of the Hot Oil Expansion Drum (151-V-001), Hot Oil Circulation Pumps (151-P-001A/B), Hot Oil Trim Cooler (151-A-001), and the Waste Heat Recovery Units (WHRUs, 141-E-001A/B/C). Therminol 72 is the selected thermal fluid with a maximum film temperature of 400°C and bulk temperature of 380°C to prevent degradation.

The closed loop hot oil system is circulated via Hot Oil Circulation Pumps. Roughly 10% of the pumped hot oil is recirculated through the Hot Oil Filter (151-F-001) for particle removal. The balance of the flow, at approximately 150°C, is split between the WHRU supply line and the cold bypass line.

Oil enters the multipass coils in the WHRUs mounted on the exhaust of each SGT-400 Power Generation Gas Turbine. Each coil is designed for 33.3% of total facility Hot oil duty, which is based on the US Gulf Coast Rich Gas Low Ambient Heat & Material Balance (U1RLH HMB) case. While the facility can operate fully in the event of one power generator outage from an electrical standpoint, the hot oil duty is reduced and the facility may be operating at a turndown rate. Hot oil exits the WHRUs between 350°C and 315°C. The end users of this hot oil are a high temperature circuit followed by a low temperature circuit.

The hot oil leaving the WHRUs first supplies the high temperature circuit, which includes the Inlet Liquids Vaporizer (110-E-002), the Regen Gas Heater (120-E-005A/B), and the Scrub Column Bottom Vaporizer (130-E-003). The flow through each of the high temperature hot oil users is adjusted by individual flow control valves at the hot oil inlet with a reset by the process side temperature controller to adjust the hot oil flow to meet the required heat duty. To account for changing flow scenarios through these users, flow through the WHRUs is effectively maintained at constant rate by adjusting the excess through the Hot Bypass line under flow control.

This excess from the hot bypass line with the hot oil returns from the users are mixed with the cooler hot oil stream from the cold bypass line quenching it to 177°C as heating medium to the low temperature circuit users. This circuit includes the Inlet Gas Heater (110-E-001), Feed Heater (120-E-003), Amine

Reboiler (120-E-002), and the Defrost Gas Heater (130-E-004). The flow through each of the low temperature hot oil users is adjusted by individual flow control valves at the hot oil inlet with a reset by the process side temperature controller to adjust the hot oil flow to meet the required heat duty. Pressure differential control valves are provided in parallel to the low temperature circuit users that serve as a bypass in case of variations in the hot oil demand by the users. The Hot Oil Trim Cooler (151-A-001) receives the hot oil returns from the low temperature circuit and removes excess heat from the circulating fluid. The quenched hot oil from the trim cooler is pumped back to the WHRU and the users network.

Make-up hot oil is supplied periodically via totes into the Hot Oil Expansion Drum. Multiple low point drains are provided across the circuit to allow for partial or full system de-inventory to portable totes when necessary.

The Hot Oil De-inventory Drum (141-V-002) is provided to allow draining of hot oil from the WHRU coils and to collect relief from PSVs on the WHRU discharge piping. After cooling, hot oil can be returned to the WHRUs via Hot Oil Return Pump (151-P-002) or transferred to totes for disposal or return to the expansion drum.

The Hot Oil Expansion Drum allows for expansion of hot oil as it is heated up and contraction when cooled down. The drum is blanketed with nitrogen to balance static head relative to the highest point (trim cooler) and to allow for thermal in-breathing (via nitrogen blanket) and out-breathing to the wet flare header.

2.8 UNIT 152 – REFRIGERANT STORAGE SYSTEM

A Refrigerant Storage unit is provided for the facility and is located on the Liquefaction Platform. The purpose of this unit is to provide ethane, propane, and i-pentane refrigerants for fill and make-up supply to the Mixed Refrigerant (MR) System. Make-up of MR is intended to be an intermittent operation. Standard iso tanks were selected for the design so empty tanks can be removed from the platform and replaced with full iso tanks. Due to the space and weight limitations, maintaining a full supply of initial fill capacity of each refrigerant is not feasible. For initial fill of refrigerant, a ship tanker, or multiple iso tanks, must be at the facility to provide additional refrigerant.

Ethane will be stored as a liquid in cryogenic tanks (152-V-001A/B). When needed, the ethane will flow to the MR make-up header driven by its own vapor pressure. To facilitate the rate of vaporization, two Ambient Ethane Vaporizers (152-E-001A/B) are used to provide ambient heating via finned tubes. The pressure in the two ethane iso tanks is controlled to the desired pressure range by common control loops. During ethane makeup when tank pressure is expected to go below the setpoint range, more ethane is sent to the vaporizer to bring back the pressure. Excess pressure is relieved via a vent valve to the dry flare header. Each ethane iso tank also has a small integral vaporizer to assist in pressure maintenance.

There are no controls associated with the Ambient Ethane Vaporizer. Ethane makeup to the MR loop is a manual operation.

Both propane and i-pentane will be stored as liquid in ambient iso tanks (152-V-002A/B and 152-V-004A/B respectively). When needed, propane will flow to the MR make-up header driven by its own vapor pressure, while i-pentane will require nitrogen to facilitate getting into the header.

Propane will flow through a dedicated sacrificial dryer (152-V-005) for the removal of any residual moisture. The pressure in the two propane iso tanks is controlled by the vent line to flare to relieve the excess pressure. Upon dropping of pressure below the setpoint, propane is expected to flash off and build back pressure. There are no controls associated with the Propane Refrigeration Dryer (152-V-005).

I-pentane will flow through a dedicated sacrificial dryer (152-V-007) for the removal of any residual moisture. The two i-pentane iso tanks are nitrogen blanketed and pressure is regulated by a set of regulators on split control to allow for breath in/breath out to dry flare.

The make-up header combines all the refrigerant components including nitrogen and methane (from the feed gas) into one header and routes into the MR suction drum piping.

2.9 UNIT 153 –FIRE PROTECTION SYSTEM

The Fire Protection System provides seawater at a regulated volume and pressure to deluge systems and fire hose stations throughout the platforms for use in fighting fires and suppressing the residual heat of the fire to avoid flashover events while allowing a safe retreat/evacuation of an area.

There are fire protection systems provided for the process units, utilities, and support facilities. The purposes of these systems are to provide fire water and firefighting foam to extinguish a fire, reduce vapor release from sumps/spill containment areas and cool equipment during a fire incident. Details of design and philosophy is covered in the Fire Protection Design Basis, N2FE-FLR-100-653-DBD-0001.

For each of the platforms, firewater is fed to the facility from vertical turbine firewater pumps which take suction directly from the sea through dedicated caisson per firewater pump. Caissons are dosed with hypochlorite to prevent biological growth. Fire water pumps are typically on standby mode and are scheduled to operate at reduced capacity one pump at a time in non-emergency operation for reliability and maintenance purposes and discharge seawater overboard. The standby pumps will be triggered by confirmed fire alarm condition whereas the optimal number of pumps will come online to meet flow demands via pressure sensors in the firewater distribution system or via pressure sensing lines dedicated per firewater pump. Each fire water pump is diesel driven. NFPA 20 shall be applied for firewater pump design, operational and testing requirements.

One jockey pump is provided per platform to maintain the firewater main pressurized, and it takes supply from the utility water distribution header.

The Living Quarters is provided with firewater from dedicated horizontal electric Firewater Pumps 153-P-001C/D taking suction directly from the utility water tanks to supply the fire sprinkler system throughout the living quarters.

A foam system is provided for the helideck via the firewater seawater supply.

For each identified fire zone, the fire water demand is based on the water required to respond to a fire in the single largest area, details of the calculation are covered in Firewater / Foam Demand Calculation Report N2FE-FLR-100-653-RPT-0001.

Common Fire and Gas Detection (F&G) systems are provided for the facilities. The purpose of these units is to provide the fire and gas detection, audible and visual alarms and mitigating actions associated with a loss of containment or a fire. The F&G system is responsible for the local and centralized warning of personnel and the preparation of equipment and personnel to handle the detected event.

2.10 UNIT 154 – FLARE SYSTEM

Two flare systems, one for each process platform, are provided for the facility. The Dry Flare System is located on the Liquefaction Platform and will handle relief loads from Liquefaction, BOG, fuel gas and refrigerant systems. The Wet Flare System is located on the Gas Treating Platform and will handle relief loads from the Heavy Hydrocarbon Removal System, Gas Treating System, Inlet Facilities, and hot oil reliefs.

2.10.1 DRY FLARE SYSTEM

The Dry Flare Package (154-PK-001) is sized based on the largest PSV case (fire scenario from the MR Interstage Drum) and the largest blowdown (from MR Accumulator) occurring simultaneously. The Dry Flare package includes a flare tip with two pilots and an air assist ring connected to an air blower for smokeless operation. The package also includes a High Energy Ignition (HEI) system backed up by a Flame Front Generator (FFG). Low pressure fuel gas from the Fuel Gas system is supplied for pilots and ignition systems. For cold start up or for any emergency, LPG cylinders are provided for the ignition package.

During normal operation, there will be a continuous sweep of fuel gas, with nitrogen backup, through two purge points into the flare collection header to prevent air ingress into the Flare stack.

The Dry Flare KO Drum (154-V-001) is a horizontal 2-inlet/1-outlet vessel provided to knock out any liquids prior to sending relief to the flare stack. It is located on the Liquefaction Platform and provides hold-up time of 20 minutes based of the largest liquid relief. Under ambient conditions, liquid accumulation will quickly evaporate. Any heavy refrigerants accumulated in the drum will be drained into totes for reuse or onshore disposal. Liquid level in the vessel is gauged and used to activate the electric strip heater (154-H-001) on high liquid level. The heater is provided on the bottom outside of the drum to vaporize any residual liquids left in the drum. On high-high liquid level, a signal is transmitted to the SIS system for facility shutdown. Also, an interlock is provided to stop the heater at high skin temperature.

2.10.2 WET FLARE SYSTEM

The Wet Flare Package (154-PK-002) is sized based on a relief event caused by control valve failure case at the inlet facilities.

The Wet Flare package includes a flare tip with two pilots. The package also includes a High Energy Ignition (HEI) system backed up by a Flame Front Generator (FFG). Low pressure fuel gas from the Fuel Gas system is supplied for pilots and ignition systems. For cold start up or for any emergency, LPG cylinders are provided for the ignition package.

During normal operation, there will be a continuous sweep of fuel gas with nitrogen backup through six purge points into the flare collection header to prevent air ingress into the Flare stack.

The Wet Flare KO Drum (154-V-002) is a horizontal 2-inlet/1-outlet vessel provided to knock out any liquid prior to sending relief to flare stack. It also serves as a collection vessel for drains on the Gas Treating Platform. An on/off pump (154-P-001) is provided to pump accumulated liquids to the Waste Amine Drum based on liquid level. The pump turns on at high liquid level and turns off at low liquid level.

Liquid level in the vessel is gauged and used to activate the electric strip heater (154-H-002) on high liquid level. The heater is provided on the bottom outside of the drum to vaporize any residual liquids left in the drum. On high-high liquid level, a signal is transmitted to the SIS system for facility shutdown. Also, an interlock is provided to stop the heater at high skin temperature and also to stop activation of the heater on low-low liquid level.

Details of pressure relief and blowdown philosophy is covered in N2FE-FLR-100-225-PHL-0003.

2.11 UNIT 155 - DRAINAGE AND EFFLUENT TREATMENT SYSTEMS

2.11.1 DRAINAGE COLLECTION

The drainage system will contain open and closed drains.
Closed drains:

- Wet closed drain header collects wet hydrocarbon liquid drains and ties into the wet flare header routed to the Wet Flare KO Drum.
- Dry closed drain header collects dry hydrocarbon liquid drains including refrigerant and LNG drains and ties into the dry flare header routed to the Dry Flare KO Drum.
- Amine drain header collects drains from the Gas Treating (AGRU) and ties into the Amine Sump (120-V-001).
- Amine drains from Amine Recovery drum, amine reflux purge water, and any liquids accumulated in the wet flare KO drum pump are routed to the Waste Amine Drum, 155-V-004 where it can be offloaded and treated onshore.

- Hot Oil header collects hot oil drains and ties into the Hot Oil De-Inventory Drum.

Open drains:

Non-hazardous versus hazardous open drains is based on area classification.

- Non-Hazardous open drain: to collect potentially contaminated storm water, washdown and firewater/deluge water from non-hazardous areas through drain boxes provided on the main deck. All drains will be collected in the Non-Hazardous Open Drain Header and routed to the wastewater treatment system. Excess firewater and storm water beyond the capacity of the collection system will be discharged overboard.
- Hazardous open drain: Minimal hydrocarbon and aqueous liquid wastes are anticipated from normal plant operation and maintenance. A dedicated open hazardous drain collection header collects drains from equipment drip pans and containment curbed areas. It will also collect any surface water from hazardous areas due to potential contamination. The drainage header will be routed to the wastewater treatment system where it is treated through an oily water separator, plus chemical treatment if required, to meet the treated water specification prior to discharging overboard.

Each platform will have a dedicated Wastewater Treatment.

For further details on drainage refer to the Drainage Philosophy, N2FE-FLR-100-225-PHL-0005.

2.11.2 WASTEWATER TREATMENT (WWT)

Wastewater collected in the open drain system is routed to Oily Water Separator units, provided on the sump deck of each platform. The Oily water separator will separate/skim oil and pump it to Slop Oil Drum for periodic transport to onshore treatment facility.

The effluent water discharge line will have an online Oil Water Analyzer to monitor oil content in the Effluent water. Effluent oil content is expected < 15 ppm. If the oil content exceeds 15 ppm, chemicals will be injected to reduce oil content in the treated water to acceptable levels prior to discharging overboard. The wastewater system is designed for peak incoming flow based on maximum rain intensity of 3 inches plus 10 m^3/hr hose washdown. Stormwater in excess of the first flush will be diverted overboard.

2.11.3 SEWAGE TREAMENT

A Sewage Treatment Package will be provided to receive and treat sanitary waste from the accommodation facilities. The design is based on the treatment of black and grey water by gravity for 120 people on board each using 0.17 m^3 (45 gallons) per day.

Combined sewage (black and grey water) from toilets, sinks, showers, and associated sanitary waste systems and collected at the Accommodations and routed to the collection tank which is fitted with a level switch. The level signal is transmitted to the unit control logic to initiate the batch treatment process.

The treatment unit operates as a “batch” process with 5 operational steps:

1. Batch Tank Fill: A measured volume of seawater is added to the batch tank by an actuated seawater valve located in the treatment package. The mixture is circulated by the macerator to reduce the solids size and mix the seawater with the sewage waste.
2. Electrolytic Oxidation: The mixture is then circulated from the batch tank, through the electrolytic cell and back to the batch tank for a timed period. A controlled DC current is applied to the cell electrodes and current flows through the mixture using seawater as an electrolyte. The DC current through the seawater generated Sodium Hypochlorite for oxidation of organics and disinfection of wastewater. Rapid oxidation occurs in the cell and is the first stage in destroying the living organisms such as fecal coliforms. During this stage, process gases are generated. The gases are separated from the process stream in the degassing chamber on top of the batch tank. The gases are diluted below the LEL and discharges to atmosphere by the on-skid dilution blower. A small amount of water based de-foaming agent is injected into the circulating stream by the defoam injection pump.
3. Polymerization and Separation: During the fill cycle, the on-skid polymer blending system draws concentrated polymer from the storage tank and blends it with freshwater in a measured ratio. At the end of the oxidation cycle, this dilute polymer mixture is injected into the treated wastewater and circulated in the batch tank. After a short period, circulation stops, and solids separation starts.
4. Effluent Discharge: After the treated solids are separated, the recirculation/overboard pump discharges clear water overboard. During discharge, a dichlorination solution (Sodium Sulfite) is injected into the discharge stream to reduce the chlorine residual below 0.5 mg/l. This treated and dechlorinated stream is compliant with IMO MEPC 227(64) for effluent water.
5. Solids Handling: Separated solid wastes are sent through a centrifuge unit that produces a waste product that requires no special transportation criteria or disposal restrictions. The captured solids are dewatered and dried within the handling unit based on a preset and automatic program. The system produces clear liquid that is separated from the solids and is routed back to the process stream for discharge overboard. Dewatered solids are automatically deposited in containers and may then be disposed of are regular garbage classified as “landfill” or “Class B” material.

ATTACHMENT F

EMISSION CALCULATIONS

Table F-1: Facility-Wide Operational Potential Air Emissions

	Short-Term Emission Rates, lb/hr													
	NO_x	CO	VOC	PM_{10}	$PM_{2.5}$	SO_2	HAP	Pb	H_2SO_4	H_2S	CO_2	CH_4	N_2O	CO_2e
PSD Stationary Sources														
FLNG1 Compressor Turbine	44.5	27.1	1.9	4.8	4.8	1.45	0.50	0	0.03	0	56,453	1.1	0.11	56,511
FLNG2 Compressor Turbine	26.7	27.1	1.9	4.8	4.8	1.45	0.50	0	0.03	0	56,453	1.1	0.11	56,511
FLNG1 Power Generating Turbines (3 units)	29.8	18.1	1.0	2.9	2.9	1.6	0.56	0	0.12	0	63,551	1.2	0.12	63,617
FLNG2 Power Generating Turbines (3 units)	29.8	18.1	1.0	2.9	2.9	1.6	0.56	0	0.12	0	63,551	1.2	0.12	63,617
FLNG1 Acid Gas Thermal Oxidizer	1.6	4.3	0.08	0.16	0.16	8.33	0.03	7.7E-06	0.638	0.004	14,373	0.6	0.001	14,389
FLNG2 Acid Gas Thermal Oxidizer	1.6	4.3	0.08	0.16	0.16	8.33	0.03	7.7E-06	0.638	0.004	14,373	0.6	0.001	14,389
FLNG1 Dry Flare (normal operation)	0.1	0.5	0.06	0.01	0.01	0.006	0.003	9.2E-07	4.3E-04	0	219	0.7	4.1E-04	237
FLNG1 Dry Flare (emergency operation)	360.5	1,460.6	5069.1	39.50	39.50	15.90	9.82	2.6E-03	1.2E+00	0	619,683	1546.9	1.2E+00	658,705
FLNG1 Dry Flare (startup)	60.1	243.4	4.72	6.58	6.58	2.651	1.636	4.3E-04	2.0E-01	0	103,275	365.3	1.9E-01	112,467
FLNG1 Dry Flare (shutdown)	3.4	13.8	0.27	0.37	0.37	0.150	0.093	2.5E-05	1.2E-02	0	5,854	20.7	1.1E-02	6,375
FLNG2 Dry Flare (normal operation)	0.1	0.5	0.06	0.01	0.01	0.006	0.003	9.2E-07	4.3E-04	0	219	0.7	4.1E-04	237
FLNG2 Dry Flare (emergency operation)	360.5	1,460.6	5069.1	39.50	39.50	15.90	9.82	2.6E-03	1.2E+00	0	619,683	1546.9	1.2E+00	658,705
FLNG2 Dry Flare (startup)	60.1	243.4	4.72	6.58	6.58	2.651	1.636	4.3E-04	2.0E-01	0	103,275	365.3	1.9E-01	112,467
FLNG2 Dry Flare (shutdown)	3.4	13.8	0.27	0.37	0.37	0.150	0.093	2.5E-05	1.2E-02	0	5,854	20.7	1.1E-02	6,375
FLNG1 Wet Flare (normal operation)	0.3	1.1	0.14	0.03	0.03	0.012	0.007	1.9E-06	9.1E-04	0	461	1.5	8.7E-04	499
FLNG1 Wet Flare (emergency operation)	251.5	1,019.0	390.8	27.56	27.56	11.10	6.85	1.8E-03	8.5E-01	0	432,337	1619.4	8.2E-01	473,064
FLNG1 Wet Flare (startup)	45.2	183.1	3.55	4.95	4.95	1.994	1.231	3.3E-04	1.5E-01	0	77,699	274.9	1.5E-01	84,614
FLNG1 Wet Flare (shutdown)	0.3	1.4	0.03	0.04	0.04	0.015	0.009	2.5E-06	1.2E-03	0	592	2.1	1.1E-03	645
FLNG2 Wet Flare (normal operation)	0.3	1.1	0.14	0.03	0.03	0.012	0.007	1.9E-06	9.1E-04	0	461	1.5	8.7E-04	499
FLNG2 Wet Flare (emergency operation)	251.5	1,019.0	390.8	27.56	27.56	11.10	6.85	1.8E-03	8.5E-01	0	432,337	1619.4	8.2E-01	473,064
FLNG2 Wet Flare (startup)	45.2	183.1	3.55	4.95	4.95	1.994	1.231	3.3E-04	1.5E-01	0	77,699	274.9	1.5E-01	84,614
FLNG2 Wet Flare (shutdown)	0.3	1.4	0.03	0.04	0.04	0.015	0.009	2.5E-06	1.2E-03	0	592	2.1	1.1E-03	645
FLNG1 Emergency Diesel Generator Engines (7 units)	426.6	89.5	2.6	5.7	5.7	0.171	0.18	0.0E+00	1.3E-02	0	18,570	0.75	0.151	18,634
FLNG2 Emergency Diesel Generator Engines (7 units)	193.5	79.5	3.9	4.5	4.5	0.138	0.14	0.0E+00	1.1E-02	0	14,956	0.61	0.121	15,008
FLNG2 Emergency Fire Pump Engines (8 units)	55.1	31.6	10.9	1.81	1.81	0.057	0.06	0.0E+00	4.4E-03	0	6,215	0.25	0.050	6,236
FSU Emergency Generator Engine	12.0	6.5	2.2	0.37	0.37	0.01	0.01	0.0E+00	8.9E-04	0	1,266	0.05	0.010	1,270
FSU Boilers (2 boilers)	1.6	0.4	0.03	0.26	0.26	1.10	0.004	9.6E-05	8.4E-02	0	1,744	0.1	1.4E-02	1,750
FSU GCU	19.7	16.6	1.09	1.47	1.47	0.592	0.3654	9.7E-05	4.5E-02	0	23,069	75.2	4.4E-02	24,963
FLNG1 & 2 Fuel Tanks (all tanks)	0	0	0.051	0	0	0	0	0	0	0	0	0	0	0
FLNG1 Fugitive Emissions	0	0	0.204	0	0	0	0	0	0	0	0	2.7	0	68
FLNG2 Fugitive Emissions	0	0	0.204	0	0	0	0	0	0	0	0	2.7	0	68

Table F-1: Facility-Wide Operational Potential Air Emissions

	Annual Emissions, tpy													
	NO_x	CO	VOC	PM_{10}	$PM_{2.5}$	SO_2	HAP	Pb	H_2SO_4	H_2S	CO_2	CH_4	N_2O	CO_2e
PSD Stationary Sources														
FLNG1 Compressor Turbine	194.4	118.4	8.13	21.0	21.0	6.33	2.2	0	0.1	0	246,774	4.7	0.5	247,029
FLNG2 Compressor Turbine	116.7	118.4	8.13	21.0	21.0	6.33	2.17	0	0.14	0	246,774	4.7	0.47	247,029
FLNG1 Power Generating Turbines (3 units)	124.8	76.0	4.44	15.7	15.7	6.86	2.3	0	0.5	0	267,179	5.0	0.5	267,455
FLNG2 Power Generating Turbines (3 units)	124.8	76.0	4.44	15.7	15.7	6.86	2.3	0	0.5	0	267,179	5.0	0.5	267,455
FLNG1 Acid Gas Thermal Oxidizer	6.6	18.3	0.54	0.66	0.66	36.45	0.12	3.3E-05	2.791	0.02	92,292	2.8	0.015	92,366
FLNG2 Acid Gas Thermal Oxidizer	6.6	18.3	0.54	0.66	0.66	36.45	0.12	3.3E-05	2.791	0.02	92,292	2.8	0.015	92,366
FLNG1 Dry Flare (normal operation)	0.6	2.3	0.27	0.06	0.06	0.02	0.02	4.0E-06	0.002	0	959	3.1	0.002	1,038
FLNG1 Dry Flare (emergency operation)	0.2	0.7	2.53	0.02	0.02	0.01	0.00	1.3E-06	0.001	0	310	0.8	0.001	329
FLNG1 Dry Flare (startup)	15.7	63.8	1.24	1.72	1.72	0.69	0.43	1.1E-04	0.053	0	27,058	95.7	0.051	29,466
FLNG1 Dry Flare (shutdown)	0.3	1.1	0.02	0.03	0.03	0.01	0.01	1.9E-06	0.001	0	454	1.6	0.001	494
FLNG2 Dry Flare (normal operation)	0.6	2.3	0.27	0.06	0.06	0.02	0.02	4.0E-06	0.002	0	959	3.1	0.002	1,038
FLNG2 Dry Flare (emergency operation)	0.2	0.7	2.53	0.02	0.02	0.01	0.005	1.3E-06	0.001	0	310	0.8	0.001	329
FLNG2 Dry Flare (startup)	15.7	63.8	1.24	1.72	1.72	0.69	0.43	1.1E-04	0.053	0	27,058	95.7	0.051	29,466
FLNG2 Dry Flare (shutdown)	0.3	1.1	0.02	0.03	0.03	0.01	0.01	1.9E-06	0.001	0	454	1.6	0.001	494
FLNG1 Wet Flare (normal operation)	1.2	4.8	0.60	0.13	0.13	0.05	0.03	8.5E-06	0.004	0	2,020	6.6	0.004	2,186
FLNG1 Wet Flare (emergency operation)	0.1	0.5	0.20	0.01	0.01	0.01	0.00	9.1E-07	0.000	0	216	0.8	0.000	237
FLNG1 Wet Flare (startup)	10.4	42.1	0.82	1.14	1.14	0.46	0.28	7.5E-05	0.035	0	17,871	63.2	0.034	19,461
FLNG1 Wet Flare (shutdown)	0.0	0.2	0.00	0.00	0.00	0.002	0.001	3.0E-07	0.0001	0	73	0.26	0.0001	79
FLNG2 Wet Flare (normal operation)	1.2	4.8	0.60	0.13	0.13	0.05	0.03	8.5E-06	0.004	0	2,020	6.6	0.004	2,186
FLNG2 Wet Flare (emergency operation)	0.1	0.5	0.20	0.01	0.01	0.01	0.00	9.1E-07	0.000	0	216	0.8	0.000	237
FLNG2 Wet Flare (startup)	10.4	42.1	0.82	1.14	1.14	0.46	0.28	7.5E-05	0.035	0	17,871	63.2	0.034	19,461
FLNG2 Wet Flare (shutdown)	0.0	0.2	0.00	0.00	0.00	0.00	0.00	3.0E-07	0.000	0	73	0.3	0.000	79
FLNG1 Emergency Diesel Generator Engines (7 units)	21.33	4.48	0.13	0.285	0.285	8.5E-03	9.0E-03	0.0E+00	6.5E-04	0	929	3.8E-02	7.5E-03	932
FLNG2 Emergency Diesel Generator Engines (7 units)	9.68	3.97	0.19	0.227	0.227	6.9E-03	7.2E-03	0.0E+00	5.3E-04	0	748	3.0E-02	6.1E-03	750
FLNG2 Emergency Fire Pump Engines (8 units)	2.8	1.58	0.54	0.090	0.090	2.9E-03	3.0E-03	0.0E+00	2.2E-04	0	311	1.3E-02	2.5E-03	312
FSU Emergency Generator Engine	0.6	0.3	0.11	0.019	0.019	5.8E-04	6.1E-04	0.0E+00	4.5E-05	0	63	0.003	5.1E-04	64
FSU Boilers (2 boilers)	6.8	1.7	0.12	1.12	1.12	4.82	0.02	4.2E-04	0.369	0	7,641	0.3	0.062	7,667
FSU GCU	1.4	1.2	0.08	0.11	0.11	0.04	0.03	7.0E-06	0.003	0	1,661	5.4	0.003	1,797
FLNG1 & 2 Fuel Tanks (all tanks)	0	0	0.44	0	0	0	0	0	0	0	0	0	0	0
FLNG1 Fugitive Emissions	0	0	0.89	0	0	0	0	0	0	0	0.006	11.9	0	298
FLNG2 Fugitive Emissions	0	0	0.89	0	0	0	0	0	0	0	0.006	11.9	0	298
Project-Wide Annual Stationary Source Totals	**673.5**	**669.3**	**41.0**	**82.9**	**82.9**	**106.7**	**10.9**	**9.0E-04**	**7.48**	**0.04**	**1,321,765**	**398.8**	**2.2**	**1,332,401**

Table F-2: FLNG1 Compressor Turbine Steady State Emissions

GE LM6000PF		Annual tpy	Max. CO lb/hr
Case number		Design Case 11	Lean Case 22
Load condition	% Base	100	100
Altitude	m	0	0
Barometric pressure	psia	14.696	14.696
Ambient temperature	°C	15	15
Ambient relative humidity	%	100	100
Air cooling type		None	None
Power at engine shaft	hp	69,796	72,022
Heat Input	kWh (LHV)	127,543	127,679
Heat rate at engine shaft	kJ/kWh (LHV basis)	8,821.9	8,558.3
Efficiency at engine shaft	% (LHV basis)	40.80%	42.06%
Fuel Heat Content	Btu/lb (LHV)	20,282	20,138
Fuel Heat Content	Btu/lb (HHV)	22,465	22,326
GT fuel flow	kg/hr	9,730.7	9,810.7
Exhaust flow	kg/s	137.78	140.77
Exhaust temperature	°C	498.32	493.57
Exhaust N2	mol %	74.376	74.579
Exhaust O2	mol %	13.518	13.553
Exhaust CO2	mol %	3.284	3.264
Exhaust Water	mol %	7.928	7.708
Exhaust Argon	mol %	0.888	0.891
NOx	ppmvd at 15% O2	25	25
CO	ppmvd at 15% O2	25	25
VOC (methane equivalent)	ppmvd at 15% O2	3	3
SO2	ppmvd at 15% O2	N/A	N/A

Calculated Heat Input

GT heat input (per turbine)	MMBtu/hr (HHV)	482.0	483.0
Exhaust MW	g/g-mol	28.391	28.411
Exhaust flow	Nm^3/hr at 0 °C	391,337	399,552
Exhaust flow	m^3/hr, actual temp.	1,105,269	1,121,522

	Design Case 11		Lean Case 22		
Calculated Emissions	15 °C Ambient		12 °C Ambient		Design Case
Pollutant	lb/MMBtu (HHV)	lb/hr (per turbine)	lb/MMBtu (HHV)	lb/hr (per turbine)	Annual emissions (tpy)
NOx	0.0921	44.4	0.0921	44.5	194.44
CO	0.0561	27.0	0.0561	27.1	118.39
VOC	0.0039	1.86	0.0039	1.86	8.13
PM10/PM2.5	0.0100	4.80	0.0100	4.80	21.02
SO2	0.003	1.45	0.003	1.45	6.33
HAP	1.0E-03	0.50	1.0E-03	0.50	2.17
Pb	0	0.0	0	0.0	0.00
H2SO4	6.8E-05	0.033	6.8E-05	0.034	0.14
CO2	116.9	56,341	116.9	56,453	246,774
CH4	0.00220	1.1	0.00220	1.06	4.65
N2O	0.00022	0.11	0.00022	0.106	0.47
CO2e	117.01	56,399	117.01	56,511	247,029

Notes:
1) Annual emissions are based on 8,760 operating hours per year for Design Gas Case Number 11.
2) Worst case CO and VOC hourly emissions are based on case number 101 from vendor performance data sheet.
3) For annual emissions, it is assumed that each compressor turbine operates for 8,760 hours per year at full load.
4) Emission rates for NOx, CO, VOC, PM10/PM2.5, and H2SO4 are based on vendor lb/MMBtu performance data and heat input.
5) Emission rate for SO2 is based on a natural gas fuel sulfur content of 20 ppmv.
6) H2SO4 emissions assume that 5% of SO2 is converted to SO3.
7) HAP emission factor is derived from EPA AP-42 Table 3.1-3.
8) 40 CFR 98 emission factors are used to calculate emission rates for CO2 (53.02 kg/MMBtu), CH4, and N2O (0.0001 kg/MMBtu).
9) CO2e emission rates use the following global warming potentials from 40 CFR 98, Table A-1: 25 for CH4, and 298 for N2O.

Table F-3: FLNG2 Compressor Turbine Steady State Emissions

GE LM6000PF		Annual tpy	Max. CO lb/hr
Case number		Design Case 11	Lean Case 22
Load condition	% Base	100	100
Altitude	m	0	0
Barometric pressure	psia	14.696	14.696
Ambient temperature	°C	15	15
Ambient relative humidity	%	100	100
Air cooling type		None	None
Power at engine shaft	hp	69,796	72,022
Heat Input	kWh (LHV)	127,543	127,679
Heat rate at engine shaft	kJ/kWh (LHV basis)	8,821.9	8,558.3
Efficiency at engine shaft	% (LHV basis)	40.80%	42.06%
Fuel Heat Content	Btu/lb (LHV)	20,282	20,138
Fuel Heat Content	Btu/lb (HHV)	22,465	22,326
GT fuel flow	kg/hr	9,730.7	9,810.7
Exhaust flow	kg/s	137.78	140.77
Exhaust temperature	°C	498.32	493.57
Exhaust N2	mol %	74.376	74.579
Exhaust O2	mol %	13.518	13.553
Exhaust CO2	mol %	3.284	3.264
Exhaust Water	mol %	7.928	7.708
Exhaust Argon	mol %	0.888	0.891
NOx	ppmvd at 15% O2	15	15
CO	ppmvd at 15% O2	25	25
VOC (methane equivalent)	ppmvd at 15% O2	3	3
SO2	ppmvd at 15% O2	N/A	N/A

Calculated Heat Input

GT heat input (per turbine)	MMBtu/hr (HHV)	482.0	483.0
Exhaust MW	g/g-mol	28.391	28.411
Exhaust flow	Nm^3/hr at 0 °C	391,337	399,552
Exhaust flow	m^3/hr, actual temp.	1,105,269	1,121,522

	Design Case 11		Lean Case 22		
Calculated Emissions	15 °C Ambient		12 °C Ambient		Design Case
Pollutant	lb/MMBtu (HHV)	lb/hr (per turbine)	lb/MMBtu (HHV)	lb/hr (per turbine)	Annual emissions (tpy)
NOx	0.0553	26.6	0.0553	26.7	116.67
CO	0.0561	27.0	0.0561	27.1	118.39
VOC	0.0039	1.86	0.0039	1.86	8.13
PM10/PM2.5	0.0100	4.80	0.0100	4.80	21.02
SO2	0.003	1.45	0.003	1.45	6.33
HAP	1.0E-03	0.50	1.0E-03	0.50	2.17
Pb	0	0.0	0	0.0	0.00
H2SO4	6.8E-05	0.033	6.8E-05	0.034	0.14
CO2	116.9	56,341	116.9	56,453	246,774
CH4	0.00220	1.1	0.00220	1.06	4.65
N2O	0.00022	0.11	0.00022	0.106	0.47
CO2e	117.01	56,399	117.01	56,511	247,029

Notes:
1) Annual emissions are based on 8,760 operating hours per year for Design Gas Case Number 11.
2) Worst case CO and VOC hourly emissions are based on case number 101 from vendor performance data sheet.
3) For annual emissions, it is assumed that each compressor turbine operates for 8,760 hours per year at full load.
4) Emission rates for NOx, CO, VOC, PM10/PM2.5, and H2SO4 are based on vendor lb/MMBtu performance data and heat input.
5) Emission rate for SO2 is based on a natural gas fuel sulfur content of 20 ppmv.
6) H2SO4 emissions assume that 5% of SO2 is converted to SO3.
7) HAP emission factor is derived from EPA AP-42 Table 3.1-3.
8) 40 CFR 98 emission factors are used to calculate emission rates for CO2 (53.02 kg/MMBtu), CH4, and N2O (0.0001 kg/MMBtu).
9) CO2e emission rates use the following global warming potentials from 40 CFR 98, Table A-1: 25 for CH4, and 298 for N2O.

Table F-4: FLNG Power Generation Turbines (x3 per plant)

Siemens SGT-400 Vendor Data		Annual tpy	Max. fuel
Case		Design	Lean Case 0
Ambient temperature	°C	15	6
Altitude	m	0	0
Barometric pressure	Bar	1.0133	1.0133
Relative humidity	%	60	60
Fuel Heat Content	kJ/kg (LHV)	47,182	46,845
Generator power output	kWe	16,013	17,290
Heat rate at generator terminal	kJ/kWeh	10,335	9,972
Thermal efficiency	%	34.83%	36.10%
GT fuel flow	kg/hr	3,507.6	3,680.6
Exhaust flow	kg/s	54.15	55.82
Oxygen reference level	%	15	15
NOx	ppmvd at 15% O2	15	15
CO	ppmvd at 15% O2	15	15
VOC	ppmvd at 15% O2	1.4	1.4
Exhaust molecular weight	kg/kmol	28.486	28.520
Nitrogen	% vol	75.019	75.320
Oxygen	% vol	14.072	14.074
Water vapor	% vol	6.896	6.579
Carbon dioxide	% vol	3.086	3.097
Argon	% vol	0.896	0.900

Calculated Heat Input and Exhaust Stack Parameters

GT heat input (per turbine)	MMBtu/hr (HHV)	174.0	181.2
WHRU inlet temp.	°C	496.8	490.7
WHRU outlet temp. (stack)	°C	395	395
Exhaust flow	Nm^3/hr at 0 °C	153,287	157,829
Exhaust flow (WHRU outlet)	m^3/hr	374,954	386,065

Calculated Emissions	Design @ 15°C		Worst Case Lean @ 15°C		Annual emissions, tons	
Pollutant	lb/MMBtu (HHV)	lb/hr (per turbine)	lb/MMBtu (HHV)	lb/hr (per turbine)	Per Turbine	3 Turbines
NOx	0.0553	9.498	0.0553	9.919	41.60	124.81
CO	0.0337	5.782	0.0337	6.037	25.32	75.97
VOC	0.0021	0.3377	0.0021	0.348	1.48	4.44
PM10/PM2.5	0.0069	1.195	0.0053	0.962	5.23	15.70
SO2	0.003	0.522	0.003	0.544	2.29	6.86
HAP	1.0E-03	0.179	1.0E-03	0.186	0.78	2.35
Pb	0	0.000	0	0.00	0.00	0.00
H2SO4	0.0002	0.040	0.0002	0.042	0.18	0.53
CO2	116.9	20,333	116.9	21,184	89,060	267,179
CH4	0.0022	0.38	0.0022	0.400	1.68	5.04
N2O	0.00022	0.038	0.00022	0.040	0.17	0.50
CO2e	117.01	20,354	117.01	21,206	89,152	267,455

Notes:
1) All vendor data shown are for 100% load, at 24 °C ambient temperature.
2) For annual emissions, it is assumed that each turbine operates for the equivalent of 8,760 hours per year at full load.
3) Emission rates for NOx, CO, VOC, and PM10/PM2.5 are based on vendor data sheet.
4) Emission rate for SO2 is based on a natural gas fuel sulfur content of 20 ppmv.
5) H2SO4 emissions assume that 5% of SO2 is converted to SO3.
6) HAP emission factor is derived from EPA AP-42 Table 3.1-3.
7) 40 CFR 98 emission factors are used to calculate emission rates for CO2 (53.02 kg/MMBtu), CH4 (0.001 kg/MMBtu), and N2O (0.0001 kg/MMBtu).
8) CO2e emission rates use the following global warming potentials from 40 CFR 98, Table A-1: 25 for CH4, and 298 for N2O.

Table F-5: Combustion Turbine Startup and Shutdown Emissions

Startup and Shutdown Emissions (lbs/event)		
Pollutant	**GE LM6000**	**Siemens SGT-400**
NOx	0.8	0.3
CO	10.3	1.1
VOC	0.7	0.13

Startup and Shutdown Emissions (lbs/hr)			
Pollutant	**Operating Condition**	**GE LM6000**	**Siemens SGT-400**
Event Duration (mins)		9	3
NOx	Steady State Rate (lb/hr)	44.5	9.92
	Steady State (lbs)	37.8	9.42
	SUSD Rate (lb/hr)	38.6	9.72
CO	Steady State Rate (lb/hr)	27.1	6.04
	Steady State (lbs)	23.0	5.74
	SUSD Rate (lb/hr)	33.3	6.84
VOC	Steady State Rate (lb/hr)	1.86	0.35
	Steady State (lbs)	1.6	0.33
	SUSD Rate (lb/hr)	2.28	0.46

SUSD rate exceeds steady state rate.

Table F-6: FLNG Acid Gas Thermal Oxidizer (Design Case Operation)

Component	MW kg/kmol	Units	Normal Flash Acid Gas	Max Flash Acid Gas	Supplemental Natural Gas (Normal Flash)	Supplemental Natural Gas (Max Flash)
Nitrogen	28	mol %	0.0100%	0.0135%	3.1924%	3.1924%
Carbon Dioxide	44	mol %	94.8569%	86.9986%	0.0010%	0.0010%
Methane	16	mol %	1.6139%	9.0087%	94.5373%	94.5373%
Ethane	30	mol %	0.0375%	0.4346%	0.7484%	0.7484%
Propane	44.1	mol %	0.0057%	0.1278%	0.1429%	0.1429%
i-Butane/n-Butane	58.1	mol %	0.0021%	0.0592%	0.5712%	0.5712%
i-Pentane/n-Pentane	72.2	mol %	0.0005%	0.0146%	0.2651%	0.2651%
C6+	142.3	mol %	0.0013%	0.0131%	0.4417%	0.4417%
H2O	18	mol %	3.4248%	3.2400%	0.0000%	0.0000%
H2S	34	mol %	0.0282%	0.0396%	0.0000%	0.0000%
M-Mercaptan	48.1	mol %	0.0000%	0.0000%	0.0004%	0.0004%
Aromatics	106.2	mol %	0.0192%	0.0504%	0.0996%	0.0996%
VOC		mol %	0.0663%	0.6996%		
Molecular Weight		g/mol	42.67	40.62	17.40	17.40
Molar Flow Rate		kmole/hr	213.1	151.9	15.6	3.9
Mass Flow Rate (calc'd))		kg/hr	9,095	6,169	272.0	68.6
Standard Volume Flow		Sm3/hr	5,040	3,591	370	93
		MMSCFD	4.27	3.04	0.31	0.08
Heat Content (LHV)		Btu/lb	149.2	921.9	20,267	20,267
Heat Input (LHV)		MMBtu/hr	2.99	12.54	12.16	3.07
Operating Temperature		°C	871	871	871	871
Control Efficiency		%	99.9%	99.9%	99.9%	99.9%
Operating Hours		hr/yr	8,760	8,760	8,760	8,760

Normal Flash				Max Flash			
Inlet Flow (lb/hr)	Outlet Flow (lb/hr)	Outlet CO2 (lb/hr)	Outlet VOC (lb/hr)	Inlet Flow (lb/hr)	Outlet Flow (lb/hr)	Outlet CO2 (lb/hr)	Outlet VOC (lb/hr)
31.6	31.6	0.0	0	8.9	8.9	0.0	0
19,287.8	19,287.8	19,287.8	0	12,604.4	12,604.4	12,604.4	0
632.0	0.6	1,736.2	0	603.9	0.6	1,659.1	0
12.8	0.013	18.8	0	44.9	0.045	65.7	0
3.3	0.003	3.3	0.003	19.1	0.019	19.0	0.019
11.8	0.012	8.9	0.012	14.2	0.014	10.7	0.014
6.7	0.007	4.1	0.007	5.1	0.005	3.1	0.005
22.2	0.022	6.8	0.022	11.5	0.011	3.5	0.011
284.9	1,736.9	0.0	0.000	192.0	1,632.3	0.0	0.000
4.4	0.004	0.0	0.000	4.4	0.004	0.0	0.000
6.5E-03	0.000	0.0	0.000	0.0	0.000	0.0	0.000
13.0	0.013	5.4	0.013	18.5	0.019	7.7	0.019

	Potential Emissions			
Pollutant	lb/MMBtu	lb/hr (Normal Flash)	lb/hr (Max Flash)	tpy
NOx	0.10	1.51	1.56	6.63
CO	0.28	4.17	4.30	18.28
VOC (acid gas)	N/A	0.057	0.068	0.249
VOC (gas comb)	0.0054	0.066	0.017	0.288
PM10/PM2.5	0.0100	0.15	0.16	0.66
SO2	N/A	8.32	8.33	36.45
HAP	1.9E-03	0.028	0.029	0.12
Pb	4.9E-07	7.4E-06	7.7E-06	3.3E-05
H2SO4	N/A	0.64	0.64	2.79
CO2	N/A	21,071	14,373	92,292
CH4	N/A	0.63	0.60	2.77
N2O	0.00022	0.003	0.001	0.01
CO2e	N/A	21,088	14,389	92,366
H2S	N/A	0.004	0.004	0.019

Notes:
1) Heat input rate is based on Fluor design waste gas rate, fuel gas rate, and gas composition to the termal oxidizer.
2) Oxidizer temperature and control efficiency based upon vendor design specification.
3) Annual emissions are based on operation for 8,760 hours per year at full load.
4) NOx, CO, and PM10/PM2.5 based upon vendor performance data.
5) VOC emissions based upon VOC content of gas streams, design control efficiency, and VOC from fuel gas combustion using emission factor in AP-42 Table 1.4-2.
6) SO2 emissions were estimated using mass balance based upon the design H2S concentration in the waste gas and 99.9 percent conversion to SO2.
7) HAP emission factor compiled from AP-42 Table 1.4-3.
8) Pb emission factor is from AP-42 Table 1.4-2.
9) H2SO4 emissions assume that 5% of SO2 is converted to SO3.
10) 40 CFR 98 emission factors are used to calculate emission rates for CO2 (53.02 kg/MMBtu), CH4 (0.001 kg/MMBtu) and N2O (0.0001 kg/MMBtu).
11) CO2e emission rates use the following global warming potentials from 40 CFR 98, Table A-1: 25 for CH4, and 298 for N2O.

Table F-7: FLNG Dry Flare (Normal Operation - Design Gas)

Fuel flow rates

Dry flare purge gas	kg/hr	36
Dry flare pilot burner	kg/hr	2
Wet flare purge gas	kg/hr	78
Wet flare pilot burner	kg/hr	2

TCEQ Equations for Equivalent Stack Parameters

Sensible heat release	qn = q*(1 - 0.048*SQRT(MW))
Equivalent diameter	d = 0.001 * SQRT(qn)

Gas Properties and Calculated Heat Input

Flare gas MW	kg/kgmol	17.74
Flare gas GCV	Btu/scf (HHV)	1,030
VOC content	% weight	7.87%
C1, C2, C3 content	% weight	85.3%
Ideal gas volume at 20 °C (68 °F)	m3/kgmol	24.06
Dry flare fuel flow	kg	38
Dry flare fuel flow	scf/hr	1,820
Dry flare heat input	MMBtu/hr (HHV)	1.9

TCEQ Equivalent Stack Parameters (Cold Flare)

Conversion factor	cal/Btu	252
Gross heat release	q, cal/s	131,182
Sensible heat release	qn, cal/s	104,661
Mean MW of feed gas	MW, kg/kgmol	17.74
Equivalent diameter	d, m	0.3235
Temperature	K	1,273
Exit velocity	m/s	20

Emission Factors

			Cold flare, lb/hr (per FLNG)	Cold flare annual tons (per FLNG)
NOx	lb/MMBtu (HHV)	0.068	0.13	0.6
CO	lb/MMBtu (HHV)	0.2755	0.52	2.3
VOC	lb/MMBtu (HHV)	0.0333	0.06	0.27
PM10/PM2.5	lb/MMBtu (HHV)	0.0075	0.014	0.06
SO2	lb/MMBtu (HHV)	0.003	0.006	0.025
HAP	lb/MMBtu (HHV)	1.9E-03	0.003	0.015
Pb	lb/MMBtu (HHV)	4.9E-07	9.2E-07	4.0E-06
H2SO4	lb/MMBtu (HHV)	2.3E-04	4.3E-04	1.9E-03
CO2	lb/MMBtu (HHV)	116.9	219	959
CH4	lb/MMBtu (HHV)	0.3811	0.7	3.1
N2O	lb/MMBtu (HHV)	0.00022	4.1E-04	0.002
CO2e	lb/MMBtu (HHV)	N/A	237	1,038

Notes:
1) Pilot fuel and purge gas sent to each flare are from Fluor Design Gas Case Dry Flare Normal Emissions.
2) Molecular weight and gross calorific value of gas sent to each flare are from Fluor Design Gas Case Dry Flare Normal Emissions.
3) Flow rate of fuel gas to flare purge and pilot burner are from Fluor Design Gas Case Dry Flare Normal Emissions.
4) Equivalent stack parameters are calculated based on the TCEQ guidance memo, "APD-ID 6v1, NSR Emission Calculations," March 2021.
5) NOx and CO emission factors from TCEQ flare emissions guidance.
6) VOC emissions based upon 99% destruction of VOCs in purge gas.
7) PM10 and PM2.5 emission factors are from AP-42 Table 1.4-2.
8) SO2 emission rate is based upon a maximum sulfur content of 20 ppmv.
9) HAP emission factor is compiled from AP-42 Table 1.4-3.
10) Pb emission factor is based on AP-42 Table 1.4-2.
11) H2SO4 emission rate assumes that 5% of SO2 converts to SO3.
12) Emission factors for CO2 and N2O are from Tables C-1 and C-2 of 40 CFR 98, Subpart C.
13) CH4 emission factor rate assumes 99% destruction of C1, C2, and C3 compounds (CH4, C2H6, C3H8) present in gas sent to flare.
14) CO2e emission rates use the following global warming potentials from 40 CFR 98, Table A-1: 25 for CH4, and 298 for N2O.

Gas Composition	Design Gas		Lean Gas		Rich Gas	
Name	Mole%	Weight%	Mole%	Weight%	Mole%	Weight%
Nitrogen	4.4718	7.0624	4.2195	6.9128	4.4174	6.3042
Carbon Dioxide	0.0011	0.0027	0.0017	0.0044	0.0013	0.0029
Methane	93.3039	84.3900	94.8019	88.9473	89.0724	72.8001
Ethane	0.3971	0.6731	0.1548	0.2722	1.1701	1.7925
Propane	0.0763	0.1897	0.0217	0.0559	0.8884	1.9958
i-Butane/n-Butane	0.4972	1.6292	0.0663	0.2254	1.2650	3.7459
i-Pentane/n-Pentane	0.4157	1.6908	0.2810	1.1856	1.7364	6.3826
C6+	0.6936	3.6981	0.3346	1.8104	1.2090	5.9191
H2O	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
M-Mercaptan	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Aromatics	0.1434	0.6640	0.1186	0.5860	0.2400	1.0569
Total	100.00	100.00	100.00	100.00	100.00	100.00
Molecular Weight		17.74		17.10		19.63
High Heating Value (HHV), BTU/scf		1030		993		1140

Table F-8: FLNG Cold Flare (Emergency Event - Design Gas)

Fuel flow rates

Cold flare purge gas	kg/hr	430000
Cold flare pilot burner	kg/hr	2
Warm flare purge gas	kg/hr	300000
Warm flare pilot burner	kg/hr	2

TCEQ Equations for Equivalent Stack Parameters

Sensible heat release	qn = q*(1 - 0.048*SQRT(MW))
Equivalent diameter	d = 0.001 * SQRT(qn)

Gas Properties and Calculated Heat Input

Flare gas MW	kg/kgmol	34.85
Flare gas GCV	Btu/scf (HHV)	2,023
VOC content	% weight	53.46%
C1, C2, C3 content	% weight	65.3%
Ideal gas volume at 20 °C (68 °F)	m3/kgmol	24.06
Cold flare fuel flow	kg/event	107,500
Cold flare fuel flow	scf/event	2,620,441
Cold flare heat input	MMBtu/event (HHV)	5,301.5
Event duration	hrs	0.25

TCEQ Equivalent Stack Parameters (Cold Flare)

Conversion factor	cal/Btu	252
Gross heat release	q, cal/s	371,108,365
Sensible heat release	qn, cal/s	265,950,110
Mean MW of feed gas	MW, kg/kgmol	34.85
Equivalent diameter	d, m	16.3
Temperature	K	1,273
Exit velocity	m/s	20

Emission Factors

			Cold flare, lb/event (per FLNG)	Cold flare annual tons (per FLNG)
NOx	lb/MMBtu (HHV)	0.068	360.5	0.2
CO	lb/MMBtu (HHV)	0.2755	1460.6	0.7
VOC	lb/MMBtu (HHV)	0.9561	5069.1	2.53
PM10/PM2.5	lb/MMBtu (HHV)	0.0075	39.502	0.02
SO2	lb/MMBtu (HHV)	0.003	15.905	0.008
HAP	lb/MMBtu (HHV)	1.9E-03	9.815	0.005
Pb	lb/MMBtu (HHV)	4.9E-07	2.6E-03	1.3E-06
H2SO4	lb/MMBtu (HHV)	2.3E-04	1.2E+00	6.1E-04
CO2	lb/MMBtu (HHV)	116.9	619,683	310
CH4	lb/MMBtu (HHV)	0.2918	1546.9	0.8
N2O	lb/MMBtu (HHV)	0.00022	1.2E+00	0.001
CO2e	lb/MMBtu (HHV)	N/A	658,705	329

Notes:
1) Pilot fuel and purge gas sent to each flare are from Fluor Design Gas Case Dry Flare Emergency Emissions.
2) Molecular weight and gross calorific value of gas sent to each flare are from Fluor Design Gas Case Dry Flare Emergency Emissions.
3) Flow rate of fuel gas to flare purge and pilot burner are from Fluor Design Gas Case Dry Flare Emergency Emissions.
4) Equivalent stack parameters are calculated based on the TCEQ guidance memo, "APD-ID 6v1, NSR Emission Calculations," March 2021.
5) NOx, CO, and VOC emission factors are from flare vendor performance specifications.
7) PM10 and PM2.5 emission factors are from AP-42 Table 1.4-2.
8) SO2 emission rate is based upon a maximum sulfur content of 20 ppmv.
9) HAP emission factor is compiled from AP-42 Table 1.4-3.
10) Pb emission factor is based on AP-42 Table 1.4-2.
11) H2SO4 emission rate assumes that 5% of SO2 converts to SO3.
12) Emission factors for CO2 and N2O are from Tables C-1 and C-2 of 40 CFR 98, Subpart C.
13) CH4 emission factor rate assumes 99% destruction of C1, C2, and C3 compounds (CH4, C2H6, C3H8) present in gas sent to flare.
14) CO2e emission rates use the following global warming potentials from 40 CFR 98, Table A-1: 25 for CH4, and 298 for N2O.
15) Emissions based upon one 15 minute event per year

Gas Composition	Design Gas		Lean Gas		Rich Gas	
Name	Mole%	Weight%	Mole%	Weight%	Mole%	Weight%
Nitrogen	4.0243	3.2347	2.8703	2.0459	3.9800	3.2093
Carbon Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Methane	28.3186	13.0356	24.9558	10.1871	26.3524	12.1694
Ethane	35.0804	30.2672	30.4121	23.2688	35.0568	30.3438
Propane	17.3644	21.9707	17.0482	19.1286	21.7915	27.6606
i-Butane/n-Butane	0.0026	0.0044	0.0027	0.0040	0.0174	0.0291
i-Pentane/n-Pentane	15.2094	31.4870	24.7108	45.3654	12.8015	26.5870
C6+	0.0002	0.0004	0.0001	0.0002	0.0002	0.0006
H2O	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
M-Mercaptan	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Aromatics	0.0000	0.0001	0.0000	0.0001	0.0000	0.0001
Total	100.00	100.00	100.00	100.00	100.00	100.00
Molecular Weight		34.85		39.30		34.74
High Heating Value (HHV), BTU/scf		2023		2281		2017

Table F-9: FLNG Dry Flare Startup

Fuel flow rates

Dry flare startup gas	kg/event	9,082,302
Dry flare pilot burner	kg/event	1048
Wet flare startup gas	kg/event	5,998,464
Wet flare pilot burner	kg/event	920
Startup Events per year	events/yr	1
Event Duration	hrs/event	524

TCEQ Equations for Equivalent Stack Parameters

Sensible heat release	qn = q*(1 - 0.048*SQRT(MW))
Equivalent diameter	d = 0.001 * SQRT(qn)

Gas Properties and Calculated Heat Input

Flare gas MW	kg/kgmol	16.80
Flare gas GCV	Btu/scf (HHV)	1,008
VOC content	% weight	1.23%
C1, C2, C3 content	% weight	95.6%
Ideal gas volume at 20 °C (68 °F)	m3/kgmol	24.06
Dry flare fuel flow	kg/event	9,082,302
Dry flare fuel flow	scf/event	459,256,479
Dry flare heat input	MMBtu/event (HHV)	462,979.3

TCEQ Equivalent Stack Parameters (Cold Flare)

Conversion factor	cal/Btu	252
Gross heat release	q, cal/s	61,848,384
Sensible heat release	qn, cal/s	49,680,243
Mean MW of feed gas	MW, kg/kgmol	16.8
Equivalent diameter	d, m	7.0
Temperature	K	1,273
Exit velocity	m/s	20

Emission Factors			Cold flare, lb/event (per FLNG)	Cold flare, lb/hr (per FLNG)	Cold flare startup tons (per FLNG)
NOx	lb/MMBtu (HHV)	0.068	31,482.6	60.08	15.7
CO	lb/MMBtu (HHV)	0.2755	127,551	243.42	63.8
VOC	lb/MMBtu (HHV)	0.0053	2473.01	4.72	1.2
PM10/PM2.5	lb/MMBtu (HHV)	0.0075	3449.6	6.58	1.7
SO2	lb/MMBtu (HHV)	0.003	1388.938	2.651	0.7
HAP	lb/MMBtu (HHV)	1.9E-03	857.2	1.636	0.43
Pb	lb/MMBtu (HHV)	4.9E-07	2.3E-01	0.00043	0.0
H2SO4	lb/MMBtu (HHV)	2.3E-04	1.1E+02	0.203	0.1
CO2	lb/MMBtu (HHV)	116.9	54,116,323	103,275	27,058.2
CH4	lb/MMBtu (HHV)	0.4135	191,442.1	365.3	95.7
N2O	lb/MMBtu (HHV)	0.00022	1.0E+02	1.9E-01	0.1
CO2e	lb/MMBtu (HHV)	N/A	58,932,791	112,467.2	29,466.4

Notes:
1) Pilot fuel and purge gas sent to each flare are from Fluor Design Gas Case Dry Flare Startup Emissions.
2) Molecular weight and gross calorific value of gas sent to each flare are from Fluor Design Gas Case Dry Flare Startup Emissions.
3) Flow rate of fuel gas to flare purge and pilot burner are from Fluor Design Gas Case Dry Flare Startup Emissions.
4) Equivalent stack parameters are calculated based on the TCEQ guidance memo, "APD-ID 6v1, NSR Emission Calculations," March 2021.
5) NOx and CO emission factors from TCEQ flare emissions guidance.
6) VOC emissions based upon 99% destruction of VOCs in purge gas.
7) PM10 and PM2.5 emission factors are from AP-42 Table 1.4-2.
8) SO2 emission rate is based upon a maximum sulfur content of 20 ppmv.
9) HAP emission factor is compiled from AP-42 Table 1.4-3.
10) Pb emission factor is based on AP-42 Table 1.4-2.
11) H2SO4 emission rate assumes that 5% of SO2 converts to SO3.
12) Emission factors for CO2 and N2O are from Tables C-1 and C-2 of 40 CFR 98, Subpart C.
13) CH4 emission factor rate assumes 99% destruction of C1, C2, and C3 compounds (CH4, C2H6, C3H8) present in gas sent to flare.
14) CO2e emission rates use the following global warming potentials from 40 CFR 98, Table A-1: 25 for CH4, and 298 for N2O.

Gas Composition	Design Gas	
Name	Mole%	Weight%
Nitrogen	0.4000	0.6669
Carbon Dioxide	1.1238	2.9433
Methane	96.3372	91.9741
Ethane	1.7648	3.1581
Propane	0.1828	0.4796
i-Butane/n-Butane	0.0812	0.2808
i-Pentane/n-Pentane	0.0305	0.1309
C6+	0.0508	0.2859
H2O	0.0147	0.0158
H2S	0.0006	0.0012
M-Mercaptan	0.0020	0.0057
Aromatics	0.0115	0.0576
Total	100.00	100.00
Molecular Weight		16.80
High Heating Value (HHV), BTU/scf		1008

Table F-10: FLNG Dry Flare Shutdown

Fuel flow rates

Dry flare shutdown gas	kg/event	152,287
Dry flare pilot burner	kg/event	310
Wet flare shutdown gas	kg/event	24,410
Wet flare pilot burner	kg/event	920
Shutdown Events per year	events/yr	1
Event Duration	hrs/event	155

TCEQ Equations for Equivalent Stack Parameters

Sensible heat release	qn = q*(1 - 0.048*SQRT(MW))
Equivalent diameter	d = 0.001 * SQRT(qn)

Gas Properties and Calculated Heat Input

Flare gas MW	kg/kgmol	16.80
Flare gas GCV	Btu/scf (HHV)	1,008
VOC content	% weight	1.23%
C1, C2, C3 content	% weight	95.6%
Ideal gas volume at 20 °C (68 °F)	m3/kgmol	24.06
Dry flare fuel flow	kg/event	152,287
Dry flare fuel flow	scf/event	7,700,558
Dry flare heat input	MMBtu/event (HHV)	7,763.0

TCEQ Equivalent Stack Parameters (Cold Flare)

Conversion factor	cal/Btu	252
Gross heat release	q, cal/s	3,505,862
Sensible heat release	qn, cal/s	2,816,114
Mean MW of feed gas	MW, kg/kgmol	16.8
Equivalent diameter	d, m	1.7
Temperature	K	1,273
Exit velocity	m/s	20

Emission Factors			Cold flare, lb/event (per FLNG)	Cold flare, lb/hr (per FLNG)	Cold flare annual tons (per FLNG)
NOx	lb/MMBtu (HHV)	0.068	527.9	3.41	0.3
CO	lb/MMBtu (HHV)	0.2755	2,139	13.80	1.1
VOC	lb/MMBtu (HHV)	0.0053	41.47	0.27	0.0
PM10/PM2.5	lb/MMBtu (HHV)	0.0075	57.8	0.37	0.0
SO2	lb/MMBtu (HHV)	0.003	23.289	0.1503	0.0
HAP	lb/MMBtu (HHV)	1.9E-03	14.4	0.093	0.0
Pb	lb/MMBtu (HHV)	4.9E-07	3.8E-03	0.000025	0.0
H2SO4	lb/MMBtu (HHV)	2.3E-04	1.8E+00	0.0115	0.0
CO2	lb/MMBtu (HHV)	116.9	907,392	5,854	453.7
CH4	lb/MMBtu (HHV)	0.4135	3,210.0	20.7	1.6
N2O	lb/MMBtu (HHV)	0.00022	1.7E+00	1.1E-02	0.0
CO2e	lb/MMBtu (HHV)	N/A	988,152	6,375.2	494.1

Notes:
1) Pilot fuel and purge gas sent to each flare are from Fluor Design Gas Case Dry Flare Shutdown Emissions.
2) Molecular weight and gross calorific value of gas sent to each flare are from Fluor Design Gas Case Dry Flare Shutdown Emissions.
3) Flow rate of fuel gas to flare purge and pilot burner are from Fluor Design Gas Case Dry Flare Shutdown Emissions.
4) Equivalent stack parameters are calculated based on the TCEQ guidance memo, "APD-ID 6v1, NSR Emission Calculations," March 2021.
5) NOx and CO emission factors from TCEQ flare emissions guidance.
6) VOC emissions based upon 99% destruction of VOCs in purge gas.
7) PM10 and PM2.5 emission factors are from AP-42 Table 1.4-2.
8) SO2 emission rate is based upon a maximum sulfur content of 20 ppmv.
9) HAP emission factor is compiled from AP-42 Table 1.4-3.
10) Pb emission factor is based on AP-42 Table 1.4-2.
11) H2SO4 emission rate assumes that 5% of SO2 converts to SO3.
12) Emission factors for CO2 and N2O are from Tables C-1 and C-2 of 40 CFR 98, Subpart C.
13) CH4 emission factor rate assumes 99% destruction of C1, C2, and C3 compounds (CH4, C2H6, C3H8) present in gas sent to flare.
14) CO2e emission rates use the following global warming potentials from 40 CFR 98, Table A-1: 25 for CH4, and 298 for N2O.

Gas Composition	Design Gas	
Name	Mole%	Weight%
Nitrogen	0.4000	0.6669
Carbon Dioxide	1.1238	2.9433
Methane	96.3372	91.9741
Ethane	1.7648	3.1581
Propane	0.1828	0.4796
i-Butane/n-Butane	0.0812	0.2808
i-Pentane/n-Pentane	0.0305	0.1309
C6+	0.0508	0.2859
H2O	0.0147	0.0158
H2S	0.0006	0.0012
M-Mercaptan	0.0020	0.0057
Aromatics	0.0115	0.0576
Total	100.00	100.00
Molecular Weight		16.80
High Heating Value (HHV), BTU/scf		1008

Table F-11: FLNG Wet Flare (Normal Operation - Design Gas)

Fuel flow rates

Dry flare purge gas	kg/hr	36
Dry flare pilot burner	kg/hr	2
Wet flare purge gas	kg/hr	78
Wet flare pilot burner	kg/hr	2

TCEQ Equations for Equivalent Stack Parameters

Sensible heat release	qn = q*(1 - 0.048*SQRT(MW))
Equivalent diameter	d = 0.001 * SQRT(qn)

Gas Properties and Calculated Heat Input

Flare gas MW	kg/kgmol	17.75
Flare gas GCV	Btu/scf (HHV)	1,030
VOC content	% weight	7.95%
C1, C2, C3 content	% weight	85.2%
Ideal gas volume at 20 °C (68 °F)	m3/kgmol	24.06
Wet flare fuel flow	kg	80
Wet flare fuel flow	scf/hr	3,829
Wet flare heat input	MMBtu/hr (HHV)	3.9

TCEQ Equivalent Stack Parameters (Cold Flare)

Conversion factor	cal/Btu	252
Gross heat release	q, cal/s	276,174
Sensible heat release	qn, cal/s	220,324
Mean MW of feed gas	MW, kg/kgmol	17.75
Equivalent diameter	d, m	0.5
Temperature	K	1,273
Exit velocity	m/s	20

Emission Factors			Wet flare, lb/hr (per FLNG)	Wet flare annual tons (per FLNG)
NOx	lb/MMBtu (HHV)	0.068	0.27	1.2
CO	lb/MMBtu (HHV)	0.2755	1.09	4.8
VOC	lb/MMBtu (HHV)	0.0346	0.137	0.60
PM10/PM2.5	lb/MMBtu (HHV)	0.0075	0.029	0.13
SO2	lb/MMBtu (HHV)	0.003	0.012	0.052
HAP	lb/MMBtu (HHV)	1.9E-03	0.007	0.032
Pb	lb/MMBtu (HHV)	4.9E-07	1.9E-06	8.5E-06
H2SO4	lb/MMBtu (HHV)	2.3E-04	9.1E-04	4.0E-03
CO2	lb/MMBtu (HHV)	116.9	461	2,020
CH4	lb/MMBtu (HHV)	0.3808	1.5	6.6
N2O	lb/MMBtu (HHV)	0.00022	8.7E-04	0.004
CO2e	lb/MMBtu (HHV)	N/A	499	2,186

Notes:
1) Pilot fuel and purge gas sent to each flare are from Fluor Design Gas Case Wet Flare Normal Emissions.
2) Molecular weight and gross calorific value of gas sent to each flare are from Fluor Design Gas Case Wet Flare Normal Emissions.
3) Flow rate of fuel gas to flare purge and pilot burner are from Fluor Design Gas Case Wet Flare Normal Emissions.
4) Equivalent stack parameters are calculated based on the TCEQ guidance memo, "APD-ID 6v1, NSR Emission Calculations," March 2021.
5) NOx and CO emission factors from TCEQ flare emissions guidance.
6) VOC emissions based upon 99% destruction of VOCs in purge gas.
7) PM10 and PM2.5 emission factors are from AP-42 Table 1.4-2.
8) SO2 emission rate is based upon a maximum sulfur content of 20 ppmv.
9) HAP emission factor is compiled from AP-42 Table 1.4-3.
10) Pb emission factor is based on AP-42 Table 1.4-2.
11) H2SO4 emission rate assumes that 5% of SO2 converts to SO3.
12) Emission factors for CO2 and N2O are from Tables C-1 and C-2 of 40 CFR 98, Subpart C.
13) CH4 emission factor rate assumes 99% destruction of C1, C2, and C3 compounds (CH4, C2H6, C3H8) present in gas sent to flare.
14) CO2e emission rates use the following global warming potentials from 40 CFR 98, Table A-1: 25 for CH4, and 298 for N2O.

Gas Composition	Design Gas		Lean Gas		Rich Gas	
Name	Mole%	Weight%	Mole%	Weight%	Mole%	Weight%
Nitrogen	4.4712	7.0566	4.2195	6.9128	4.4174	6.3042
Carbon Dioxide	0.0011	0.0027	0.0017	0.0044	0.0013	0.0029
Methane	93.2911	84.3209	94.8018	88.9469	89.0724	72.8001
Ethane	0.3970	0.6726	0.1548	0.2722	1.1701	1.7925
Propane	0.0763	0.1896	0.0217	0.0560	0.8884	1.9958
i-Butane/n-Butane	0.4971	1.6278	0.0663	0.2254	1.2650	3.7459
i-Pentane/n-Pentane	0.4156	1.6894	0.2810	1.1857	1.7364	6.3826
C6+	0.6935	3.6950	0.3346	1.8106	1.2090	5.9191
H2O	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
M-Mercaptan	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Aromatics	0.1571	0.7454	0.1186	0.5861	0.2400	1.0569
Total	100.00	100.00	100.00	100.00	100.00	100.00
Molecular Weight		17.75		17.10		19.63
High Heating Value (HHV), BTU/scf		1030		993		1140

Table F-12: FLNG Wet Flare (Emergency Event - Design Gas)

Fuel flow rates

Dry flare purge gas	kg/hr	430000
Dry flare pilot burner	kg/hr	2
Wet flare purge gas	kg/hr	300000
Wet flare pilot burner	kg/hr	2

TCEQ Equations for Equivalent Stack Parameters

Sensible heat release	qn = q*(1 - 0.048*SQRT(MW))
Equivalent diameter	d = 0.001 * SQRT(qn)

Gas Properties and Calculated Heat Input

Flare gas MW	kg/kgmol	16.49
Flare gas GCV	Btu/scf (HHV)	957
VOC content	% weight	4.12%
C1, C2, C3 content	% weight	97.9%
Ideal gas volume at 20 °C (68 °F)	m3/kgmol	24.06
Wet flare fuel flow	kg/event	75,000
Wet flare fuel flow	scf/event	3,863,752
Wet flare heat input	MMBtu/event (HHV)	3,698.8
Event duration	hrs	0.25

TCEQ Equivalent Stack Parameters (Warm flare)

Conversion factor	cal/Btu	252
Gross heat release	q, cal/s	258,912,813
Sensible heat release	qn, cal/s	208,446,090
Mean MW of feed gas	MW, kg/kgmol	16.49
Equivalent diameter	d, m	14.4
Temperature	K	1,273
Exit velocity	m/s	20

Emission Factors			Warm flare, lb/event (per FLNG)	Warm flare annual tons (per FLNG)
NOx	lb/MMBtu (HHV)	0.068	251.5	0.1
CO	lb/MMBtu (HHV)	0.2755	1019.0	0.5
VOC	lb/MMBtu (HHV)	0.1057	390.8	0.20
PM10/PM2.5	lb/MMBtu (HHV)	0.0075	27.559	0.01
SO2	lb/MMBtu (HHV)	0.003	11.096	0.006
HAP	lb/MMBtu (HHV)	1.9E-03	6.848	0.003
Pb	lb/MMBtu (HHV)	4.9E-07	1.8E-03	9.1E-07
H2SO4	lb/MMBtu (HHV)	2.3E-04	8.5E-01	4.2E-04
CO2	lb/MMBtu (HHV)	116.9	432,337	216
CH4	lb/MMBtu (HHV)	0.4378	1619.4	0.8
N2O	lb/MMBtu (HHV)	0.00022	8.2E-01	0.000
CO2e	lb/MMBtu (HHV)	N/A	473,064	237

Notes:
1) Pilot fuel and purge gas sent to each flare are from Fluor Design Gas Case Wet Flare Emergency Emissions.
2) Molecular weight and gross calorific value of gas sent to each flare are from Fluor Design Gas Case Wet Flare Emergency Emissions.
3) Flow rate of fuel gas to flare purge and pilot burner are from Fluor Design Gas Case Wet Flare Emergency Emissions.
4) Equivalent stack parameters are calculated based on the TCEQ guidance memo, "APD-ID 6v1, NSR Emission Calculations," March 2021.
5) NOx and CO emission factors from TCEQ flare emissions guidance.
6) VOC emissions based upon 99% destruction of VOCs in purge gas.
7) PM10 and PM2.5 emission factors are from AP-42 Table 1.4-2.
8) SO2 emission rate is based upon a maximum sulfur content of 20 ppmv.
9) HAP emission factor is compiled from AP-42 Table 1.4-3.
10) Pb emission factor is based on AP-42 Table 1.4-2.
11) H2SO4 emission rate assumes that 5% of SO2 converts to SO3.
12) Emission factors for CO2 and N2O are from Tables C-1 and C-2 of 40 CFR 98, Subpart C.
13) CH4 emission factor rate assumes 99% destruction of C1, C2, and C3 compounds (CH4, C2H6, C3H8) present in gas sent to flare.
14) CO2e emission rates use the following global warming potentials from 40 CFR 98, Table A-1: 25 for CH4, and 298 for N2O.
15) Emissions based upon one 15 minute event per year

Gas Composition	Design Gas		Lean Gas		Rich Gas	
Name	Mole%	Weight%	Mole%	Weight%	Mole%	Weight%
Nitrogen	4.4712	7.0566	4.2195	6.9128	4.4174	6.3042
Carbon Dioxide	0.4007	0.6806	0.5002	0.8628	0.4008	0.6495
Methane	0.0050	0.0133	0.0050	0.0135	0.0050	0.0127
Ethane	97.3625	94.7105	98.7513	97.5564	94.1056	87.3392
Propane	1.7628	3.2140	0.4459	0.8257	3.5780	6.2242
i-Butane/n-Butane	0.1826	0.4882	0.0508	0.1380	1.1395	2.9069
i-Pentane/n-Pentane	0.0812	0.2862	0.0204	0.0729	0.4590	1.5434
C6+	0.0306	0.1337	0.0265	0.1178	0.1590	0.6637
H2O	0.0509	0.2919	0.0316	0.1802	0.0944	0.5250
H2S	0.1123	0.1227	0.1571	0.1743	0.0399	0.0416
M-Mercaptan	0.0006	0.0012	0.0006	0.0012	0.0006	0.0012
Aromatics	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	0.0115	0.0588	0.0112	0.0583	0.0187	0.0937
Total	104.47	107.06	104.22	106.91	104.42	106.31
Molecular Weight		16.49		16.24		17.29
High Heating Value (HHV), BTU/scf		957		943		1004

Table F-13: FLNG Wet Flare Startup

Fuel flow rates

Dry flare startup gas	kg/event	9,082,302
Dry flare pilot burner	kg/event	1048
Wet flare startup gas	kg/event	5,998,464
Wet flare pilot burner	kg/event	920
Startup Events per year	events/yr	1
Event Duration	hrs/event	460

TCEQ Equations for Equivalent Stack Parameters

Sensible heat release	qn = q*(1 - 0.048*SQRT(MW))
Equivalent diameter	d = 0.001 * SQRT(qn)

Gas Properties and Calculated Heat Input

Flare gas MW	kg/kgmol	16.80
Flare gas GCV	Btu/scf (HHV)	1,008
VOC content	% weight	1.23%
C1, C2, C3 content	% weight	95.6%
Ideal gas volume at 20 °C (68 °F)	m3/kgmol	24.06
Wet flare fuel flow	kg/event	5,998,464
Wet flare fuel flow	scf/event	303,318,856
Wet flare heat input	MMBtu/event (HHV)	305,777.6

TCEQ Equivalent Stack Parameters (Warm flare)

Conversion factor	cal/Btu	252
Gross heat release	q, cal/s	46,531,379
Sensible heat release	qn, cal/s	37,376,728
Mean MW of feed gas	MW, kg/kgmol	16.8
Equivalent diameter	d, m	6.1
Temperature	K	1,273
Exit velocity	m/s	20

Emission Factors			Warm flare, lb/event (per FLNG)	Wet flare, lb/hr (per FLNG)	Warm flare annual tons (per FLNG)
NOx	lb/MMBtu (HHV)	0.068	20,792.9	45.20	10.4
CO	lb/MMBtu (HHV)	0.2755	84,242	183.13	42.1
VOC	lb/MMBtu (HHV)	0.0053	1,633	3.55	0.8
PM10/PM2.5	lb/MMBtu (HHV)	0.0075	2278.3	4.95	1.1
SO2	lb/MMBtu (HHV)	0.003	917.333	1.99	0.5
HAP	lb/MMBtu (HHV)	1.9E-03	566.1	1.231	0.3
Pb	lb/MMBtu (HHV)	4.9E-07	1.5E-01	0.00033	0.0
H2SO4	lb/MMBtu (HHV)	2.3E-04	7.0E+01	0.15	0.0
CO2	lb/MMBtu (HHV)	116.9	35,741,469	77,699	17,870.7
CH4	lb/MMBtu (HHV)	0.4135	126,439.1	274.9	63.2
N2O	lb/MMBtu (HHV)	0.00022	6.7E+01	1.5E-01	0.0
CO2e	lb/MMBtu (HHV)	N/A	38,922,536	84,614.2	19,461.3

Notes:
1) Pilot fuel and purge gas sent to each flare are from Fluor Design Gas Case Wet Flare Startup Emissions.
2) Molecular weight and gross calorific value of gas sent to each flare are from Fluor Design Gas Case Wet Flare Startup Emissions.
3) Flow rate of fuel gas to flare purge and pilot burner are from Fluor Design Gas Case Wet Flare Startup Emissions.
4) Equivalent stack parameters are calculated based on the TCEQ guidance memo, "APD-ID 6v1, NSR Emission Calculations," March 2021.
5) NOx and CO emission factors from TCEQ flare emissions guidance.
6) VOC emissions based upon 99% destruction of VOCs in purge gas.
7) PM10 and PM2.5 emission factors are from AP-42 Table 1.4-2.
8) SO2 emission rate is based upon a maximum sulfur content of 20 ppmv.
9) HAP emission factor is compiled from AP-42 Table 1.4-3.
10) Pb emission factor is based on AP-42 Table 1.4-2.
11) H2SO4 emission rate assumes that 5% of SO2 converts to SO3.
12) Emission factors for CO2 and N2O are from Tables C-1 and C-2 of 40 CFR 98, Subpart C.
13) CH4 emission factor rate assumes 99% destruction of C1, C2, and C3 compounds (CH4, C2H6, C3H8) present in gas sent to flare.
14) CO2e emission rates use the following global warming potentials from 40 CFR 98, Table A-1: 25 for CH4, and 298 for N2O.

Gas Composition	Design Gas	
Name	Mole%	Weight%
Nitrogen	0.4000	0.6669
Carbon Dioxide	1.1238	2.9433
Methane	96.3372	91.9741
Ethane	1.7648	3.1581
Propane	0.1828	0.4796
i-Butane/n-Butane	0.0812	0.2808
i-Pentane/n-Pentane	0.0305	0.1309
C6+	0.0508	0.2859
H2O	0.0147	0.0158
H2S	0.0006	0.0012
M-Mercaptan	0.0020	0.0057
Aromatics	0.0115	0.0576
Total	100.00	100.00
Molecular Weight		16.80
High Heating Value (HHV), BTU/scf		1008

Table F-14: FLNG Wet Flare Shutdown

Fuel flow rates

Dry flare shutdown gas	kg/event	152,287
Dry flare pilot burner	kg/event	491.2
Wet flare shutdown gas	kg/event	24,410
Wet flare pilot burner	kg/event	920
Shutdown Events per year	events/yr	1
Event Duration	hrs/event	246

TCEQ Equations for Equivalent Stack Parameters

Sensible heat release	qn = q*(1 - 0.048*SQRT(MW))
Equivalent diameter	d = 0.001 * SQRT(qn)

Gas Properties and Calculated Heat Input

Flare gas MW	kg/kgmol	16.80
Flare gas GCV	Btu/scf (HHV)	1,008
VOC content	% weight	1.23%
C1, C2, C3 content	% weight	95.6%
Ideal gas volume at 20 °C (68 °F)	m3/kgmol	24.06
Wet flare fuel flow	kg/event	24,410
Wet flare fuel flow	scf/event	1,234,318
Wet flare heat input	MMBtu/event (HHV)	1,244.3

TCEQ Equivalent Stack Parameters (Warm flare)

Conversion factor	cal/Btu	252
Gross heat release	q, cal/s	354,653
Sensible heat release	qn, cal/s	284,878
Mean MW of feed gas	MW, kg/kgmol	16.8
Equivalent diameter	d, m	0.5
Temperature	K	1,273
Exit velocity	m/s	20

Emission Factors

Pollutant	Units	Factor	Warm flare, lb/event (per FLNG)	Wet flare, lb/hr (per FLNG)	Warm flare annual tons (per FLNG)
NOx	lb/MMBtu (HHV)	0.068	84.6	0.34	0.0
CO	lb/MMBtu (HHV)	0.2755	343	1.40	0.2
VOC	lb/MMBtu (HHV)	0.0053	7	0.03	0.0
PM10/PM2.5	lb/MMBtu (HHV)	0.0075	9.3	0.04	0.0
SO2	lb/MMBtu (HHV)	0.003	3.733	0.0152	0.0
HAP	lb/MMBtu (HHV)	1.9E-03	2.3	0.009	0.0
Pb	lb/MMBtu (HHV)	4.9E-07	6.1E-04	0.00000	0.0
H2SO4	lb/MMBtu (HHV)	2.3E-04	2.9E-01	0.0012	0.0
CO2	lb/MMBtu (HHV)	116.9	145,445	592	72.7
CH4	lb/MMBtu (HHV)	0.4135	514.5	2.1	0.3
N2O	lb/MMBtu (HHV)	0.00022	2.7E-01	1.1E-03	0.0
CO2e	lb/MMBtu (HHV)	N/A	158,390	644.9	79.2

Notes:
1) Pilot fuel and purge gas sent to each flare are from Fluor Design Gas Case Wet Flare Shutdown Emissions.
2) Molecular weight and gross calorific value of gas sent to each flare are from Fluor Design Gas Case Wet Flare Shutdown Emissions.
3) Flow rate of fuel gas to flare purge and pilot burner are from Fluor Design Gas Case Wet Flare Shutdown Emissions.
4) Equivalent stack parameters are calculated based on the TCEQ guidance memo, "APD-ID 6v1, NSR Emission Calculations," March 2021.
5) NOx and CO emission factors from TCEQ flare emissions guidance.
6) VOC emissions based upon 99% destruction of VOCs in purge gas.
7) PM10 and PM2.5 emission factors are from AP-42 Table 1.4-2.
8) SO2 emission rate is based upon a maximum sulfur content of 20 ppmv.
9) HAP emission factor is compiled from AP-42 Table 1.4-3.
10) Pb emission factor is based on AP-42 Table 1.4-2.
11) H2SO4 emission rate assumes that 5% of SO2 converts to SO3.
12) Emission factors for CO2 and N2O are from Tables C-1 and C-2 of 40 CFR 98, Subpart C.
13) CH4 emission factor rate assumes 99% destruction of C1, C2, and C3 compounds (CH4, C2H6, C3H8) present in gas sent to flare.
14) CO2e emission rates use the following global warming potentials from 40 CFR 98, Table A-1: 25 for CH4, and 298 for N2O.

Gas Composition	DGAA	
Name	Mole%	Weight%
Nitrogen	0.4000	0.6669
Carbon Dioxide	1.1238	2.9433
Methane	96.3372	91.9741
Ethane	1.7648	3.1581
Propane	0.1828	0.4796
i-Butane/n-Butane	0.0812	0.2808
i-Pentane/n-Pentane	0.0305	0.1309
C6+	0.0508	0.2859
H2O	0.0147	0.0158
H2S	0.0006	0.0012
M-Mercaptan	0.0020	0.0057
Aromatics	0.0115	0.0576
Total	100.00	100.00
Molecular Weight		16.80
High Heating Value (HHV), BTU/scf		1008

Table F-15: FLNG1 Emergency Generator Engines (CAT 3516)

Fuel Data

Fuel type		ULSD
Fuel heat content	Btu/gal	138,000
Fuel density	kg/m3	890
Fuel sulfur content	% weight	0.0015
Conversion factor	Btu/kcal	3.97
Conversion factor	kJ/kcal	4.184
Conversion factor	HHV/LHV	1.063

Engine Data

Make/Model		CAT 3516 DITA
Rated power	kWm	1750
Exhaust temperature at engine outlet	^{o}C	496.2
Exhaust flow at engine outlet temp	m3/min	378.8
Operating Hours	hrs/yr/engine	100

Tetra Tech assumptions/calculations

Engine load	%	100
Fuel flow	gal/hr	124.1
Heat input rate	MMBtu/hr (HHV)	17.1
Brake specific fuel consumption	g/kWh	x`x
Volumetric exhaust flow	m^3/hr	22,728

Vendor Potential Site Variation Emission Rates

NOx	g/kWh	16.92
CO	g/kWh	3.50
PM	g/kWh	0.20
VOC	g/kWh	0.08

Calculated Emissions

		Short term emissions, lb/hr	Annual emissions, tons
Pollutant	lb/MMBtu (HHV)	(per engine)	(per engine)
NOx	N/A	65.3	3.26
CO	N/A	13.5	0.68
VOC	N/A	0.31	0.016
PM10/PM2.5	N/A	0.77	0.039
SO2	0.0015	0.026	1.3E-03
HAP	1.6E-03	0.027	1.3E-03
Pb	0.0E+00	0.0E+00	0.0E+00
H2SO4	1.1E-04	2.0E-03	9.8E-05
CO2	163.1	2,792	140
CH4	0.0066	0.113	5.7E-03
N2O	0.0013	0.023	1.1E-03
CO2e	N/A	2,802	140

Notes:
1) Engine power output, fuel consumption, exhaust temperature, and exhaust flow are based on performance data for a Caterpi 3516 engine.
2) For annual emissions, it is assumed that each emergency generator may operate up to 100 hours per year at full load.
3) Engines meet Tier II Limits (40 CFR 60 Subpart IIII for emergency engines > 560 kW) which are prorated averages across all operating loads. NOx, CO, HC, and PM emissions based upon full load. Potential Site Variation emission rates from vendor. VOC emisisons presumed equal to HC.
4) Emission rate for SO2 is based on fuel sulfur content of 0.0015 wt %.
5) H2SO4 emissions assume that 5% of SO2 is converted to SO3.
6) HAP emission factor is derived from EPA AP-42 Tables 3.4-3 and 3.4-4 (and Table 1.3-11 for metals).
7) 40 CFR 98 emission factors are used to calculate emission rates for CO2 (73.96 kg/MMBtu), CH4 (0.003 kg/MMBtu) and N2O (0.0006 kg/MMBtu).

Table F-16: FLNG1 Emergency Generator Engines (CAT 3512)

Fuel Data

Fuel type		ULSD
Fuel heat content	Btu/gal	138,000
Fuel density	kg/m3	890
Fuel sulfur content	% weight	0.0015
Conversion factor	Btu/kcal	3.97
Conversion factor	kJ/kcal	4.184
Conversion factor	HHV/LHV	1.063

Engine Data

Make/Model		CAT 3512
Rated power	kWm	1100
Exhaust temperature at engine outlet	^oC	524
Exhaust flow at engine outlet temp	m3/min	258.9
Operating Hours	hrs/yr/engine	100

Tetra Tech assumptions/calculations

Engine load	%	100
Fuel flow	gal/hr	80.7
Heat input rate	MMBtu/hr (HHV)	11.1
Brake specific fuel consumption	g/kWh	247.0
Volumetric exhaust flow	m^3/hr	15,534

Vendor Potential Site Variation Emission Rates

NOx	g/kWh	14.35
CO	g/kWh	3.50
PM	g/kWh	0.44
VOC	g/kWh	0.30

Calculated Emissions		Short term emissions, lb/hr	Annual emissions, tons
Pollutant	lb/MMBtu (HHV)	(per engine)	(per engine)
NOx	N/A	34.8	1.74
CO	N/A	8.5	0.42
VOC	N/A	0.72	0.036
PM10/PM2.5	N/A	1.07	0.054
SO2	0.0015	0.017	8.4E-04
HAP	1.6E-03	0.018	8.8E-04
Pb	0.0E+00	0.0E+00	0.0E+00
H2SO4	1.1E-04	1.3E-03	6.4E-05
CO2	163.1	1,816	91
CH4	0.0066	0.074	3.7E-03
N2O	0.0013	0.015	7.4E-04
CO2e	N/A	1,822	91

Notes:
1) Engine power output, fuel consumption, exhaust temperature, and exhaust flow are based on performance data for a Caterpi 3516 engine.
2) For annual emissions, it is assumed that each emergency generator may operate up to 100 hours per year at full load.
3) Engines meet Tier II Limits (40 CFR 60 Subpart IIII for emergency engines > 560 kW) which are prorated averages across all operating loads. NOx, CO, HC, and PM emissions based upon full load. Potential Site Variation emission rates from vendor. VOC emisisons presumed equal to HC.
4) Emission rate for SO2 is based on fuel sulfur content of 0.0015 wt %.
5) H2SO4 emissions assume that 5% of SO2 is converted to SO3.
6) HAP emission factor is derived from EPA AP-42 Tables 3.4-3 and 3.4-4 (and Table 1.3-11 for metals).
7) 40 CFR 98 emission factors are used to calculate emission rates for CO2 (73.96 kg/MMBtu), CH4 (0.003 kg/MMBtu) and N2O (0.0006 kg/MMBtu).

Table F-17: FLNG2 Emergency Generator Engines (CAT 3512C)

Fuel Data

Fuel type		ULSD
Fuel heat content	Btu/gal	138,000
Fuel density	kg/m3	890
Fuel sulfur content	% weight	0.0015
Conversion factor	Btu/kcal	3.97
Conversion factor	kJ/kcal	4.184
Conversion factor	HHV/LHV	1.063

Engine Data

Make/Model		CAT 3512C
Rated power	kWm	1821
Exhaust temperature at engine outlet	^{o}C	419.6
Exhaust flow at engine outlet temp	m3/min	378.50
Operating Hours	hrs/yr/engine	100

Tetra Tech assumptions/calculations

Engine load	%	100
Fuel flow	gal/hr	117.1
Heat input rate	MMBtu/hr (HHV)	16.2
Brake specific fuel consumption	g/kWh	216.5
Volumetric exhaust flow	m^3/hr	22,710

Vendor Potential Site Variation Emission Rates

NOx	g/kWh	8.80
CO	g/kWh	3.50
PM	g/kWh	0.20
VOC	g/kWh	0.18

Calculated Emissions		Short term emissions, lb/hr	Annual emissions, tons
Pollutant	lb/MMBtu (HHV)	(per engine)	(per engine)
NOx	N/A	35.3	1.77
CO	N/A	14.1	0.70
VOC	N/A	0.72	0.036
PM10/PM2.5	N/A	0.80	0.040
SO2	0.0015	0.024	1.2E-03
HAP	1.6E-03	0.025	1.3E-03
Pb	0.0E+00	0.0E+00	0.0E+00
H2SO4	1.1E-04	1.9E-03	9.3E-05
CO2	163.1	2,635	132
CH4	0.0066	0.107	5.3E-03
N2O	0.0013	0.021	1.1E-03
CO2e	N/A	2,644	132

Notes:
1) Engine power output, fuel consumption, exhaust temperature, and exhaust flow are based on performance data for a Caterpi 3516 engine.
2) For annual emissions, it is assumed that each emergency generator may operate up to 100 hours per year at full load.
3) Engines meet Tier II Limits (40 CFR 60 Subpart IIII for emergency engines > 560 kW) which are prorated averages across all operating loads. NOx, CO, HC, and PM emissions based upon full load. Potential Site Variation emission rates from vendor. VOC emisisons presumed equal to HC.
4) Emission rate for SO2 is based on fuel sulfur content of 0.0015 wt %.
5) H2SO4 emissions assume that 5% of SO2 is converted to SO3.
6) HAP emission factor is derived from EPA AP-42 Tables 3.4-3 and 3.4-4 (and Table 1.3-11 for metals).
7) 40 CFR 98 emission factors are used to calculate emission rates for CO2 (73.96 kg/MMBtu), CH4 (0.003 kg/MMBtu) and N2O (0.0006 kg/MMBtu).

Table F-18: FLNG2 Emergency Generator Engines (CAT C18)

Fuel Data

Fuel type		ULSD
Fuel heat content	Btu/gal	138,000
Fuel density	kg/m3	890
Fuel sulfur content	% weight	0.0015
Conversion factor	Btu/kcal	3.97
Conversion factor	kJ/kcal	4.184
Conversion factor	HHV/LHV	1.063

Engine Data

Make/Model		CAT C18
Rated power	hp	803
Exhaust temperature at engine outlet	^oC	376.5
Exhaust flow at engine outlet temp	m3/min	102.57
Operating Hours	hrs/yr/engine	100

Tetra Tech assumptions/calculations

Engine load	%	100
Fuel flow	gal/hr	39.6
Heat input rate	MMBtu/hr (HHV)	5.5
Brake specific fuel consumption	g/kWh	222.7
Volumetric exhaust flow	m^3/hr	6,154

Vendor Potential Site Variation Emission Rates

NOx	g/kWh	6.40
CO	g/kWh	3.50
PM	g/kWh	0.20
VOC	g/kWh	0.10

Calculated Emissions		Short term emissions, lb/hr	Annual emissions, tons
Pollutant	lb/MMBtu (HHV)	(per engine)	(per engine)
NOx	N/A	8.45	0.42
CO	N/A	4.62	0.23
VOC	N/A	0.13	0.007
PM10/PM2.5	N/A	0.26	0.013
SO2	0.0015	0.008	4.1E-04
HAP	1.6E-03	0.009	4.3E-04
Pb	0.0E+00	0.0E+00	0.0E+00
H2SO4	1.1E-04	6.3E-04	3.1E-05
CO2	163.1	891	45
CH4	0.0066	0.036	1.8E-03
N2O	0.0013	0.007	3.6E-04
CO2e	N/A	894	45

Notes:
1) Engine power output, fuel consumption, exhaust temperature, and exhaust flow are based on performance data for a Caterpi 3516 engine.
2) For annual emissions, it is assumed that each emergency generator may operate up to 100 hours per year at full load.
3) Engines meet Tier II Limits (40 CFR 60 Subpart IIII for emergency engines > 560 kW) which are prorated averages across all operating loads. NOx, CO, HC, and PM emissions based upon full load. Potential Site Variation emission rates from vendor. VOC emisisons presumed equal to HC.
4) Emission rate for SO2 is based on fuel sulfur content of 0.0015 wt %.
5) H2SO4 emissions assume that 5% of SO2 is converted to SO3.
6) HAP emission factor is derived from EPA AP-42 Tables 3.4-3 and 3.4-4 (and Table 1.3-11 for metals).
7) 40 CFR 98 emission factors are used to calculate emission rates for CO2 (73.96 kg/MMBtu), CH4 (0.003 kg/MMBtu) and N2O (0.0006 kg/MMBtu).

Table F-19: FLNG2 Emergency Fire Pump Engines (Clarke UFAC28)

Fuel Data

Fuel type		ULSD
Fuel heat content	Btu/gal	138,000
Fuel density	kg/m3	890
Fuel sulfur content	% weight	0.0015
Conversion factor	Btu/kcal	3.97
Conversion factor	kJ/kcal	4.184
Conversion factor	HHV/LHV	1.063

Engine Data

Make/Model		Clarke UFAC28
Rated power	hp	800
Exhaust temperature at engine outlet	^{o}C	560
Exhaust flow at engine outlet temp	m3/min	121.30
Operating Hours	hrs/yr/engine	100

Tetra Tech assumptions/calculations

Engine load	%	100
Fuel flow	gal/hr	40.0
Heat input rate	MMBtu/hr (HHV)	5.52
Brake specific fuel consumption	g/kWh	225.7
Volumetric exhaust flow	m^3/hr	7,278

Vendor Potential Site Variation Emission Rates

NOx	g/kWh	6.40
CO	g/kWh	3.50
PM	g/kWh	0.20
VOC	g/kWh	1.20

Calculated Emissions		Short term emissions, lb/hr	Annual emissions, tons
Pollutant	lb/MMBtu (HHV)	(per engine)	(per engine)
NOx	N/A	8.4	0.42
CO	N/A	4.6	0.23
VOC	N/A	1.58	0.079
PM10/PM2.5	N/A	0.26	0.013
SO2	0.0015	0.008	4.1E-04
HAP	1.6E-03	0.009	4.3E-04
Pb	0.0E+00	0.0E+00	0.0E+00
H2SO4	1.1E-04	6.3E-04	3.2E-05
CO2	163.1	900	45
CH4	0.0066	0.037	1.8E-03
N2O	0.0013	0.007	3.7E-04
CO2e	N/A	903	45

Notes:
1) Engine power output, fuel consumption, exhaust temperature, and exhaust flow are based on performance data for a Cat 3516 engine.
2) For annual emissions, it is assumed that each emergency generator may operate up to 100 hours per year at full load.
3) Engines meet Tier II Limits (40 CFR 60 Subpart IIII for emergency engines > 560 kW) which are prorated averages across al operating loads. NOx, CO, HC, and PM emissions based upon full load. Potential Site Variation emission rates from vendor. emisisons presumed equal to HC.
4) Emission rate for SO2 is based on fuel sulfur content of 0.0015 wt %.
5) H2SO4 emissions assume that 5% of SO2 is converted to SO3.
6) HAP emission factor is derived from EPA AP-42 Tables 3.4-3 and 3.4-4 (and Table 1.3-11 for metals).
7) 40 CFR 98 emission factors are used to calculate emission rates for CO2 (73.96 kg/MMBtu), CH4 (0.003 kg/MMBtu) and N (0.0006 kg/MMBtu).

Table F-20: FLNG2 Emergency Fire Pump Engines (Clarke UFAD38)

Fuel Data

Fuel type		ULSD
Fuel heat content	Btu/gal	138,000
Fuel density	kg/m3	890
Fuel sulfur content	% weight	0.0015
Conversion factor	Btu/kcal	3.97
Conversion factor	kJ/kcal	4.184
Conversion factor	HHV/LHV	1.063

Engine Data

Make/Model		Clarke UFAD38
Rated power	hp	350
Exhaust temperature at engine outlet	^oC	433
Exhaust flow at engine outlet temp	m3/min	66.84
Operating Hours	hrs/yr/engine	100

Tetra Tech assumptions/calculations

Engine load	%	100
Fuel flow	gal/hr	18.10
Heat input rate	MMBtu/hr (HHV)	2.50
Brake specific fuel consumption	g/kWh	233.5
Volumetric exhaust flow	m^3/hr	4,010

Vendor Potential Site Variation Emission Rates

NOx	g/kWh	4.00
CO	g/kWh	3.50
PM	g/kWh	0.20
VOC	g/kWh	1.20

Calculated Emissions		Short term emissions, lb/hr	Annual emissions, tons
Pollutant	lb/MMBtu (HHV)	(per engine)	(per engine)
NOx	N/A	2.3	0.12
CO	N/A	2.0	0.10
VOC	N/A	0.69	0.035
PM10/PM2.5	N/A	0.12	0.006
SO2	0.0015	0.004	1.9E-04
HAP	1.6E-03	0.004	2.0E-04
Pb	0.0E+00	0.0E+00	0.0E+00
H2SO4	1.1E-04	2.9E-04	1.4E-05
CO2	163.1	407	20
CH4	0.0066	0.017	8.3E-04
N2O	0.0013	0.003	1.7E-04
CO2e	N/A	409	20

Notes:
1) Engine power output, fuel consumption, exhaust temperature, and exhaust flow are based on performance data for a Caterpi 3516 engine.
2) For annual emissions, it is assumed that each emergency generator may operate up to 100 hours per year at full load.
3) Engines meet Tier II Limits (40 CFR 60 Subpart IIII for emergency engines > 560 kW) which are prorated averages across all operating loads. NOx, CO, HC, and PM emissions based upon full load. Potential Site Variation emission rates from vendor. VOC emisisons presumed equal to HC.
4) Emission rate for SO2 is based on fuel sulfur content of 0.0015 wt %.
5) H2SO4 emissions assume that 5% of SO2 is converted to SO3.
6) HAP emission factor is derived from EPA AP-42 Tables 3.4-3 and 3.4-4 (and Table 1.3-11 for metals).
7) 40 CFR 98 emission factors are used to calculate emission rates for CO2 (73.96 kg/MMBtu), CH4 (0.003 kg/MMBtu) and N2O (0.0006 kg/MMBtu).

Table F-21: FSU Emergency Generator Engine

Fuel Data

Fuel type		ULSD
Fuel heat content	Btu/gal	138,000
Fuel density	kg/m3	890
Fuel sulfur content	% weight	0.0015
Conversion factor	Btu/kcal	3.97
Conversion factor	kJ/kcal	4.184
Conversion factor	HHV/LHV	1.063

Engine Data

Make/Model		KTA38-D(M)
Number of Engines		1
Rated power	kWm	847
Exhaust temperature at engine outlet	^oC	450
Exhaust flow at engine outlet temp	m3/min	145.1
Operating Hours	hrs/yr/engine	100

Tetra Tech assumptions/calculations

Engine load	%	100
Fuel flow	gal/hr	56.3
Heat input rate	MMBtu/hr (HHV)	7.77
Brake specific fuel consumption	g/kWh	223.7
Volumetric exhaust flow	m^3/hr	8,705

40 CFR 89, Tier II Emission Standards for Emergency Engines

NOx	g/kWh	6.40
CO	g/kWh	3.50
PM	g/kWh	0.20
VOC	g/kWh	1.20

Calculated Emissions		Short term emissions, lb/hr	Annual emissions, tons
Pollutant	lb/MMBtu (HHV)	(per engine)	(per engine)
NOx	N/A	12.0	0.60
CO	N/A	6.5	0.33
VOC	N/A	2.2	0.11
PM10/PM2.5	N/A	0.37	0.019
SO2	0.0015	0.012	5.8E-04
HAP	1.6E-03	0.012	6.1E-04
Pb	0.0E+00	0.0E+00	0.0E+00
H2SO4	1.1E-04	8.9E-04	4.5E-05
CO2	163.1	1,266	63
CH4	0.0066	0.051	2.6E-03
N2O	0.0013	0.010	5.1E-04
CO2e	N/A	1,270	64

Notes:
1) Engine power output, fuel consumption, exhaust temperature, and exhaust flow are based on performance data for a Cummins KTA38-D(M) 850 engine.
2) For annual emissions, it is assumed that the auxiliary generator operates for the equivalent of 48 hours per year at full load.
3) NOx, CO, HC , and PM emissions based upon IMO Tier II limits. VOC emisisons presumed equal to HC.
4) Emission rate for SO2 is based on fuel sulfur content of 0.0015 wt %.
5) H2SO4 emissions assume that 5% of SO2 is converted to SO3.
6) HAP emission factor is derived from EPA AP-42 Tables 3.4-3 and 3.4-4 (and Table 1.3-11 for metals).
7) 40 CFR 98 emission factors are used to calculate emission rates for CO2 (73.96 kg/MMBtu), CH4 (0.003 kg/MMBtu) and N2O (0.0006 kg/MMBtu).
8) CO2e emission rates use the following global warming potentials from 40 CFR 98, Table A-1: 25 for CH4, and 298 for N2O.

Table F-22: FSU Boilers

Placeholder Data from Technica

Heat input rate (total 2 units)	MMBtu/hr (HHV)	10.7
Fuel type	Distillate Oil	
EPA F-factor, Fd	dscf/MMBtu	9,190
EPA F-factor, Fw	wscf/MMBtu	10,320

Tetra Tech assumptions/calculations

Natural gas heat content	Btu/scf (HHV)	1,020
Exhaust moisture	% volume	10.9%
Dry exhaust O2	% volume	3.0
Wet exhaust O2	% volume	2.53
NOx	ppmvd at 3% O2	9
CO	ppmvd at 3% O2	50
Exhaust temperature	°C	175
Exhaust volumetric flow	acfh	198,179
Exhaust volumetric flow	m3/hr at 275 °C	5,612
Operating Hours	hrs/yr	8,760

Hourly and Annual Emission Totals		Short-term emissions, lb/hr	Annual emissions, tons
Pollutant	lb/MMBtu (HHV)	(2 boilers)	(2 boilers)
NOx	0.1449	1.55	6.79
CO	0.0362	0.388	1.70
VOC	0.0025	0.026	0.12
PM10/PM2.5	0.0239	0.256	1.12
SO2	0.1029	1.10	4.82
HAP	0.0003	0.004	1.6E-02
Pb	9.0E-06	9.6E-05	4.2E-04
H2SO4	7.9E-03	0.084	0.37
CO2	163.1	1,744	7,641
CH4	0.0066	0.07	0.3
N2O	0.00132	0.014	0.06
CO2e	N/A	1,750	7,667

Notes:
1) Heat input rate is based on 5,000 kg/hr/boiler steam, two boilers, and 33,479 Btu/lb steam.
2) Exhaust moisture content is estimated using F-factors from EPA Method 19.
3) Dry exhaust O2 content is assumed based on typical boiler performance.
4) Volumetric exhaust flow is calculated usingEquation 19-2 from EPA Method 19, using Fw and 2.7% ambient moisture, at actual exhaust temperature and wet O2 concentration.
5) Exhaust temperature and exit velocity are assumed values based on a typical mid-size boiler.
6) Annual emissions are based on operation for 8,760 hours per year at full load.
7) NOx, CO, VOC, PM10/PM2.5, and SO2 emission factors are from AP-42 Tables 1.3-1, 1.3-2, and 1.3-3. S = 0.1 wt%
8) HAP emission factor compiled from AP-42 Tables 1.3-9 and 1.3-10.
9) Pb emission factor is from AP-42 Table 1.3-10.
10) H2SO4 emissions assume that 5% of SO2 is converted to SO3.
11) 40 CFR 98, Subpart C, Tables C-1 and C-2 emission factors are used to calculate emission rates for CO2 (73.96 kg/MMBtu), CH4 (0.003 kg/MMBtu) and N2O (0.0006 kg/MMBtu).
12) CO2e emission rates use the following global warming potentials from 40 CFR 98, Table A-1: 25 for CH4, and 298 for N2O.

Table F-23: FSU Gas Combustion Unit (Design Gas)

Fuel flow rates

Boil Off Gas	kg/hr	4000
Pilot burner	kg/hr	2

Gas Properties and Calculated Heat Input

Gas MW	kg/kgmol	17.74
Gas GCV	Btu/scf (HHV)	1,030
VOC content	% weight	7.87%
C1, C2, C3 content	% weight	85.3%
Ideal gas volume at 20 °C (68 °F)	m3/kgmol	24.06
GCU fuel flow	kg	4,002
GCU fuel flow	scf/hr	191,643
GCU heat input	MMBtu/hr (HHV)	197.4
Operating Hours	hrs/yr	144

Emission Factors			GCU, lb/hr	GCU annual tons
NOx	lb/MMBtu (HHV)	0.100	19.74	1.42
CO	lb/MMBtu (HHV)	0.0840	16.58	1.19
VOC	lb/MMBtu (HHV)	0.0055	1.09	0.08
PM10/PM2.5	lb/MMBtu (HHV)	0.0075	1.471	0.11
SO2	lb/MMBtu (HHV)	0.003	0.592	0.043
HAP	lb/MMBtu (HHV)	1.9E-03	0.365	0.026
Pb	lb/MMBtu (HHV)	4.9E-07	9.7E-05	7.0E-06
H2SO4	lb/MMBtu (HHV)	2.3E-04	4.5E-02	3.3E-03
CO2	lb/MMBtu (HHV)	116.9	23,069	1,661
CH4	lb/MMBtu (HHV)	0.3811	75.2	5.4
N2O	lb/MMBtu (HHV)	0.00022	4.4E-02	0.003
CO2e	lb/MMBtu (HHV)	N/A	24,963	1,797

Notes:
1) Boil off gas (BOG) rate equal to 0.15% of FSU capacity based upon Golar Penguin design specifications.
2) Molecular weight and gross calorific value of BOG from Fluor Design Gas Case Dry Flare Normal Emissions.
3) Equivalent stack parameters are calculated based on the TCEQ guidance memo, "APD-ID 6v1, NSR Emission Calculations," March 2021.
4) NOx, CO, VOC, PM10 and PM2.5 emission factors are from AP-42 Table 1.4-2.
5) SO2 emission rate is based upon a maximum sulfur content of 20 ppmv.
6) HAP emission factor is compiled from AP-42 Table 1.4-3.
7) Pb emission factor is based on AP-42 Table 1.4-2.
8) H2SO4 emission rate assumes that 5% of SO2 converts to SO3.
9) Emission factors for CO2 and N2O are from Tables C-1 and C-2 of 40 CFR 98, Subpart C.
10) CH4 emission factor rate assumes 99.9% destruction of C1, C2, and C3 compounds (CH4, C2H6, C3H8) present in gas sent to flare.
11) CO2e emission rates use the following global warming potentials from 40 CFR 98, Table A-1: 25 for CH4, and 298 for N2O.

Gas Composition	Design Gas		Lean Gas		Rich Gas	
Name	Mole%	Weight%	Mole%	Weight%	Mole%	Weight%
Nitrogen	4.4718	7.0624	4.2195	6.9128	4.4174	6.3042
Carbon Dioxide	0.0011	0.0027	0.0017	0.0044	0.0013	0.0029
Methane	93.3039	84.3900	94.8019	88.9473	89.0724	72.8001
Ethane	0.3971	0.6731	0.1548	0.2722	1.1701	1.7925
Propane	0.0763	0.1897	0.0217	0.0559	0.8884	1.9958
i-Butane/n-Butane	0.4972	1.6292	0.0663	0.2254	1.2650	3.7459
i-Pentane/n-Pentane	0.4157	1.6908	0.2810	1.1856	1.7364	6.3826
C6+	0.6936	3.6981	0.3346	1.8104	1.2090	5.9191
H2O	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
M-Mercaptan	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Aromatics	0.1434	0.6640	0.1186	0.5860	0.2400	1.0569
Total	100.00	100.00	100.00	100.00	100.00	100.00
Molecular Weight		17.74		17.10		19.63
High Heating Value (HHV), BTU/scf		1030		993		1140

Table F-24: FLNG Organic Liquids Storage Tank Emissions

Variable	Description	Units			Value
L_T	Total Loss = Ls + Lw	Ton/yr			See Table
L_S	Standing Loss = 365 Vv Wv Ke Ks	lb/yr			See Table
L_W	Working Loss = 0.001 Mv Pv Q Kn Kp	lb/yr			See Table
DPb	Breather Vent Pressure Setting Range	psi	AP-42 typical ±0.03		0.06
I	Solar Insolation Factor	Btu/ft^2-day	AP-42 Table 7.1-7		1462
P_A	Atmospheric Pressure	psia	AP-42 Table 7.1-7		14.69
T	Annual Average Temperature	°F	AP-42 Table 7.1-7		61.5
T_{AX}	Average Annual Maximum Temperature	°R	AP-42 Table 7.1-7		537.2
T_{AN}	Average Annual Minimum Temperature	°R	AP-42 Table 7.1-7		521.2
T_{AA}	Daily average temperature	°R	AP-42 Eqn. 1-30		529.2
T_B	Liquid bulk temperature	°R	AP-42 Eqn. 1-31		530.3
T_{LA}	Daily average liquid surface temperature	°R	AP-42 Eqn. 1-28		531.7
T_{LX}	Maximum T_{LA}	°R	AP-42 Fig. 7.1-17		536.3
T_{Ln}	Minimum T_{LA}	°R	AP-42 Fig. 7.1-17		527.1
T_V	Average vapor temperature	°R	AP-42 Eqn. 1-33		532.8
DT_A	Daily Average Ambient Temperature Range	°R	T_{AX} - T_{AN}		16.0
ΔT_V	Daily vapor temperature range	°R	AP-42 Eqn. 1-7		18.5
K_N	Working loss turnover factor		Turnovers < 36		1
Kp	Product Factor		AP-42 for diesel		1

Tank	Material	V/H Tank Type	D Tank Estimated Diameter (ft)	H/L Tank Estimated Length (ft)	Tank Effective Diameter (ft)	Tank Effective Height/ Length (ft)	Capacity Tank Capacity (gal)	Color Paint Color	Condition	a Paint Solar Absorbance Factor	Mv Vapor Molecular Weight	A Antoine Vapor Pressure Equation Constant	B Antoine Vapor Pressure Equation Constant	P_{VA} Vapor Pressure @ T_{LA} (psia)	P_{VX} Vapor Pressure @ T_{Lx} (psia)	P_{VN} Vapor Pressure @ T_{Ln} (psia)	W_V Stock Vapor density (lb/ft^3)	Annual Through-put (gals)	Hvo Vapor Space Outage (ft)	Vv Vapor Space Volume (ft3)	T_{LA} Daily Average Liquid Surface Temp °R	ΔPV Daily Vapor Pressure Range	K_E Vapor Space Expan. Factor	Ks Vented Vapor Sat. Factor	L_S Standing Loss (lb/yr)	L_W Working Loss (lb/yr)	L_T Total Loss (ton/yr)
Pioneer 1 Fuel Oil Storage Tank #4P-1	#2 Oil	H	19.7	39.5	31.48	15.49	90,216	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	25,000	7.75	6030.9	532.4	0.00279	0.0309	0.9961	14.72	0.73	0.008
Pioneer 1 Fuel Oil Storage Tank #4S-1	#2 Oil	H	15.7	31.3	25.01	12.31	45,234	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	25,000	6.15	3023.9	532.4	0.00279	0.0309	0.9969	7.39	0.73	0.004
Pioneer 1 Fuel Oil Storage Tank #4S-2	#2 Oil	H	15.6	31.3	24.96	12.28	44,940	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	25,000	6.14	3004.2	532.4	0.00279	0.0309	0.9969	7.34	0.73	0.004
Pioneer 2 Fuel Oil Tank (1P)	#2 Oil	H	12.6	25.1	20.05	9.87	23,302	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	25,000	4.93	1557.7	532.4	0.00279	0.0309	0.9975	3.81	0.73	0.002
Pioneer 2 Fuel Oil Tank (1S)	#2 Oil	H	15.4	30.9	24.63	12.12	43,193	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	25,000	6.06	2887.4	532.4	0.00279	0.0309	0.9969	7.05	0.73	0.004
Pioneer 2 Fuel Oil Tank (2P)	#2 Oil	H	13.9	27.8	22.15	10.90	31,412	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	25,000	5.45	2099.9	532.4	0.00279	0.0309	0.9972	5.13	0.73	0.003
Pioneer 2 Fuel Oil Tank (2S)	#2 Oil	H	13.9	27.8	22.15	10.90	31,412	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	25,000	5.45	2099.9	532.4	0.00279	0.0309	0.9972	5.13	0.73	0.003
Pioneer 2 Fuel Oil Tank (3P)	#2 Oil	H	16.5	33.0	26.33	12.96	52,781	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	25,000	6.48	3528.4	532.4	0.00279	0.0309	0.9967	8.62	0.73	0.005
Pioneer 2 Non-Toxic Oil	#2 Oil	H	18.7	37.3	29.79	14.66	76,453	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	76,453	7.33	5110.9	532.4	0.00279	0.0309	0.9963	12.47	2.22	0.007
Pioneer 3 Diesel Fuel Tank 5P	#2 Oil	H	16.1	32.3	25.77	12.68	49,455	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	33,000	6.34	3306.1	532.4	0.00279	0.0309	0.9968	8.07	0.96	0.005
Pioneer 3 Diesel Fuel Tank 5S	#2 Oil	H	16.5	33.0	26.30	12.94	52,588	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	33,000	6.47	3515.5	532.4	0.00279	0.0309	0.9967	8.58	0.96	0.005
Pioneer 3 Diesel Fuel Tank 7P	#2 Oil	H	16.0	32.0	25.55	12.57	48,195	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	33,000	6.29	3221.8	532.4	0.00279	0.0309	0.9968	7.87	0.96	0.004
Pioneer 3 Diesel Fuel Tank 7S	#2 Oil	H	16.0	32.0	25.55	12.57	48,195	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	33,000	6.29	3221.8	532.4	0.00279	0.0309	0.9968	7.87	0.96	0.004
Pioneer 3 Dirty Oil Tank 8C	#2 Oil	H	9.5	19.1	15.22	7.49	10,189	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	10,189	3.74	681.1	532.4	0.00279	0.0309	0.9981	1.67	0.30	0.001
Pioneer 4 Fuel Oil Storage Tank #4P-1	#2 Oil	H	19.7	39.5	31.48	15.49	90,216	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	25,000	7.75	6030.9	532.4	0.00279	0.0309	0.9961	14.72	0.73	0.008
Pioneer 4 Fuel Oil Storage Tank #4S-1	#2 Oil	H	15.7	31.3	25.01	12.31	45,234	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	25,000	6.15	3023.9	532.4	0.00279	0.0309	0.9969	7.39	0.73	0.004
Pioneer 4 Fuel Oil Storage Tank #4S-2	#2 Oil	H	15.6	31.3	24.96	12.28	44,940	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	25,000	6.14	3004.2	532.4	0.00279	0.0309	0.9969	7.34	0.73	0.004
Pioneer 5 Fuel Oil Tank (1P)	#2 Oil	H	12.6	25.1	20.05	9.87	23,302	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	39,000	4.93	1557.7	532.4	0.00279	0.0309	0.9975	3.81	1.13	0.002
Pioneer 5 Fuel Oil Tank (1S)	#2 Oil	H	15.4	30.9	24.63	12.12	43,193	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	39,000	6.06	2887.4	532.4	0.00279	0.0309	0.9969	7.05	1.13	0.004
Pioneer 5 Fuel Oil Tank (2P)	#2 Oil	H	13.9	27.8	22.15	10.90	31,412	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	39,000	5.45	2099.9	532.4	0.00279	0.0309	0.9972	5.13	1.13	0.003
Pioneer 5 Fuel Oil Tank (2S)	#2 Oil	H	13.9	27.8	22.15	10.90	31,412	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	39,000	5.45	2099.9	532.4	0.00279	0.0309	0.9972	5.13	1.13	0.003
Pioneer 5 Fuel Oil Tank (3P)	#2 Oil	H	16.5	33.0	26.33	12.96	52,781	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	39,000	6.48	3528.4	532.4	0.00279	0.0309	0.9967	8.62	1.13	0.005
Pioneer 5 Non-Toxic Oil	#2 Oil	H	18.7	37.3	29.79	14.66	76,453	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	76,453	7.33	5110.9	532.4	0.00279	0.0309	0.9963	12.47	2.22	0.007
Pioneer 6 Diesel Fuel Tank 5P	#2 Oil	H	16.1	32.3	25.77	12.68	49,455	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	33,000	6.34	3306.1	532.4	0.00279	0.0309	0.9968	8.07	0.96	0.005
Pioneer 6 Diesel Fuel Tank 5S	#2 Oil	H	16.5	33.0	26.30	12.94	52,588	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	33,000	6.47	3515.5	532.4	0.00279	0.0309	0.9967	8.58	0.96	0.005
Pioneer 6 Diesel Fuel Tank 7P	#2 Oil	H	16.0	32.0	25.55	12.57	48,195	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	33,000	6.29	3221.8	532.4	0.00279	0.0309	0.9968	7.87	0.96	0.004
Pioneer 6 Diesel Fuel Tank 7S	#2 Oil	H	16.0	32.0	25.55	12.57	48,195	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	33,000	6.29	3221.8	532.4	0.00279	0.0309	0.9968	7.87	0.96	0.004
Pioneer 6 Dirty Oil Tank 8C	#2 Oil	H	9.5	19.1	15.22	7.49	10,189	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	10,189	3.74	681.1	532.4	0.00279	0.0309	0.9981	1.67	0.30	0.001
Pioneer 7 Fuel Oil Storage Tank #4P-1	#2 Oil	H	19.7	39.5	31.48	15.49	90,216	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	25,000	7.75	6030.9	532.4	0.00279	0.0309	0.9961	14.72	0.73	0.008
Pioneer 7 Fuel Oil Storage Tank #4S-1	#2 Oil	H	15.7	31.3	25.01	12.31	45,234	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	25,000	6.15	3023.9	532.4	0.00279	0.0309	0.9969	7.39	0.73	0.004
Pioneer 7 Fuel Oil Storage Tank #4S-2	#2 Oil	H	15.6	31.3	24.96	12.28	44,940	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	25,000	6.14	3004.2	532.4	0.00279	0.0309	0.9969	7.34	0.73	0.004
Pioneer 1 Fuel Oil Day Tank	#2 Oil	H	15.6	31.3	24.96	12.28	1,210	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	14,520	6.14	3004.2	532.4	0.00279	0.0309	0.9969	7.34	0.42	0.004
Pioneer 1 Lube Oil Tank	#2 Oil	H	15.6	31.3	24.96	12.28	1,235	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	14,820	6.14	3004.2	532.4	0.00279	0.0309	0.9969	7.34	0.43	0.004
Pioneer 1 Lube Oil Purifier Tank	#2 Oil	H	15.6	31.3	24.96	12.28	311	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	3,732	6.14	3004.2	532.4	0.00279	0.0309	0.9969	7.34	0.11	0.004
Pioneer 1 Waste Oil Tank	#2 Oil	H	15.6	31.3	24.96	12.28	9,828	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	39,312	6.14	3004.2	532.4	0.00279	0.0309	0.9969	7.34	1.14	0.004
Pioneer 2 Fuel Oil Day Tank	#2 Oil	H	15.6	31.3	24.96	12.28	4,754	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	19,016	6.14	3004.2	532.4	0.00279	0.0309	0.9969	7.34	0.55	0.004
Pioneer 2 Lube Oil Tank	#2 Oil	H	15.6	31.3	24.96	12.28	1,428	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	17,136	6.14	3004.2	532.4	0.00279	0.0309	0.9969	7.34	0.50	0.004
Pioneer 2 Waste Oil Tank	#2 Oil	H	15.6	31.3	24.96	12.28	9,007	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	36,028	6.14	3004.2	532.4	0.00279	0.0309	0.9969	7.34	1.05	0.004
Pioneer 4 Fuel Oil Day Tank	#2 Oil	H	15.6	31.3	24.96	12.28	1,210	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	14,520	6.14	3004.2	532.4	0.00279	0.0309	0.9969	7.34	0.42	0.004
Pioneer 4 Lube Oil Tank	#2 Oil	H	15.6	31.3	24.96	12.28	1,235	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	14,820	6.14	3004.2	532.4	0.00279	0.0309	0.9969	7.34	0.43	0.004
Pioneer 4 Lube Oil Purifier Tank	#2 Oil	H	15.6	31.3	24.96	12.28	311	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	3,732	6.14	3004.2	532.4	0.00279	0.0309	0.9969	7.34	0.11	0.004
Pioneer 4 Waste Oil Tank	#2 Oil	H	15.6	31.3	24.96	12.28	9,828	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	39,312	6.14	3004.2	532.4	0.00279	0.0309	0.9969	7.34	1.14	0.004
Pioneer 5 Fuel Oil Day Tank	#2 Oil	H	15.6	31.3	24.96	12.28	1,210	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	14,520	6.14	3004.2	532.4	0.00279	0.0309	0.9969	7.34	0.42	0.004
Pioneer 5 Lube Oil Tank	#2 Oil	H	15.6	31.3	24.96	12.28	1,428	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	17,136	6.14	3004.2	532.4	0.00279	0.0309	0.9969	7.34	0.50	0.004
Pioneer 5 Waste Oil Tank	#2 Oil	H	15.6	31.3	24.96	12.28	9,007	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	36,028	6.14	3004.2	532.4	0.00279	0.0309	0.9969	7.34	1.05	0.004

Tank	Tank Specifications										Material Specifications																	
		V/H	D	H/L			Capacity	Color		a	Mv	A	B	P_{VA}	P_{VX}	P_{VN}	W_V		Hvo	Vv	T_{LA}	ΔPV	K_E	Ks	L_S	L_W	L_T
	Material	Tank Type	Tank Estimated Diameter (ft)	Tank Estimated Length (ft)	Tank Effective Diameter (ft)	Tank Effective Height/ Length (ft)	Tank Capacity (gal)	Paint Color	Condition	Paint Solar Absorbance Factor	Vapor Molecular Weight	Antoine Vapor Pressure Equation Constant		Vapor Pressure @ T_{LA} (psia)	Vapor Pressure @ T_{Lx} (psia)	Vapor Pressure @ T_{Ln} (psia)	Stock Vapor density (lb/ft^3)	Annual Through-put (gals)	Vapor Space Outage (ft)	Vapor Space Volume (ft3)	Daily Average Liquid Surface Temp °R	Daily Vapor Pressure Range	Vapor Space Expan. Factor	Vented Vapor Sat. Factor	Standing Loss (lb/yr)	Working Loss (lb/yr)	Total Loss (ton/yr)
Pioneer 6 Day Tank Main	#2 Oil	H	15.6	31.3	24.96	12.28	3,006	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	36,072	6.14	3004.2	532.4	0.00279	0.0309	0.9969	7.34	1.05	0.004
Pioneer 6 Day Tank Emergency	#2 Oil	H	15.6	31.3	24.96	12.28	1,260	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	15,120	6.14	3004.2	532.4	0.00279	0.0309	0.9969	7.34	0.44	0.004
Pioneer 7 Fuel Oil Day Tank	#2 Oil	H	15.6	31.3	24.96	12.28	1,210	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	14,520	6.14	3004.2	532.4	0.00279	0.0309	0.9969	7.34	0.42	0.004
Pioneer 7 Lube Oil Tank	#2 Oil	H	15.6	31.3	24.96	12.28	1,235	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	14,820	6.14	3004.2	532.4	0.00279	0.0309	0.9969	7.34	0.43	0.004
Pioneer 7 Lube Oil Purifier Tank	#2 Oil	H	15.6	31.3	24.96	12.28	311	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	3,732	6.14	3004.2	532.4	0.00279	0.0309	0.9969	7.34	0.11	0.004
Pioneer 7 Waste Oil Tank	#2 Oil	H	15.6	31.3	24.96	12.28	9,828	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	39,312	6.14	3004.2	532.4	0.00279	0.0309	0.9969	7.34	1.14	0.004
Pioneer 7 Day Tank Main	#2 Oil	H	15.6	31.3	24.96	12.28	3,066	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	36,792	6.14	3004.2	532.4	0.00279	0.0309	0.9969	7.34	1.07	0.004
Pioneer 7 Day Tank Emergency	#2 Oil	H	15.6	31.3	24.96	12.28	1,260	White	Average	0.25	130.0	12.101	8,907	0.00955	0.01103	0.0082	0.000217	15,120	6.14	3004.2	532.4	0.00279	0.0309	0.9969	7.34	0.44	0.004

TOTAL 0.222

Basis: Calculations based on AP-42 Chapter 7.1 *Organic Liquid Storage Tank*.
Vv = vapor space volume, ft3, per Equation 1-3. Vv = $[(\pi/4)D^2]$Hvo
D = tank diameter, ft. Effective D for horizontal tanks = SQRT[(LD)/(π/4)] per Equation 1-14
H = tank height, ft. Effective h for horizontal tanks = (π/4)/D per Equation 1-15
L = tank length
Hvo = vapor space outage, ft, per Equation 1-16. Half effective height for horizontal tank
Hs = shell height
Hl = liquid height, assumed to be half full
Ls = 365Ke$[(\pi/4)D^2]$HvoKsWv
K_E = vapor space expansion factor, per day, see Equation 1-5.
ΔTV = Daily vapor temperature range, see Equation 1-7.
T_{LA} = Daily average liquid surface temperature, see Equation 1-28.
P_V = Vapor pressure, see Equation 1-25 based on T_{LA}, T_{LX}, T_{LN}
W_V = Stock vapor density, see Equation 1-22
ΔPV = Daily vapor pressure range, see Equation 1-9

Table F-25: FLNG Fugitive Evaporative Emissions

Annual Hours of Operation	8,760
CH_4 constituent of the Nat Gas	92.35%
CO_2 constituent of the Nat Gas	0.005%
VOC constituent of the Nat Gas	6.59%

UNCONTROLLED EMISSIONS

Component	Phase	No. of Components[1] (per FLNG)	Emission Factor [2] (lb/hr-component)	Hourly Potential VOC Emissions (lb/hr)[4]	Annual Potential VOC Emissions (tpy)[5]	Hourly Potential CO_2 Emissions (lb/hr) [4]	Annual Potential CO_2 Emissions (tpy) [5]	Hourly Potential CH_4 Emissions (lb/hr) [4]	Annual Potential CH_4 Emissions (tpy) [5]	Hourly Potential CO_2e Emissions (lb/hr) [6]	Annual Potential CO_2e Emissions (tpy) [6]
Valves	Gas/Vapor	2,410	0.00992	1.58	6.9	0.0	0.0	22.1	96.7	551.9	2,417.4
Flanges	Gas/Vapor	4,691	0.00086	0.27	1.16	0.0	0.0	3.7	16.3	93.1	407.9
Compressor Seals	Gas/Vapor	19	0.0194	0.024	0.11	0.0	0.0	0.3	1.5	8.5	37.3
Pumps	Light Liquid [8]	6	0.00529	2.1E-03	0.009	0.0	0.0	0.03	0.1	0.7	3.2
Connectors	Gas/Vapor	220	0.00044	6.4E-03	0.028	0.0	0.0	0.09	0.39	2.2	9.8
Acid Gas Flanges	Gas/Vapor[9]	50	0.00086	3.0E-04	0.001	0.04	0.2	0.004	0.02	0.1	0.6
Refrigerant Flanges	Gas/Vapor[10]	370	0.00086	3.2E-01	1.394	0.0	0.0	0.00	0.00	0.0	0.0
Feed Gas Flanges	Gas/Vapor	2429	0.00086	1.4E-01	0.603	0.0	0.0	1.93	8.4	48.2	211.2
TOTAL		7,396		2.33	10.2	0.0	0.2	28.2	123.5	704.9	3,087.5

CONTROLLED EMISSIONS

Component	Phase	No. of Components[1] (per FLNG)	Control Efficiencies [28MID with AVO] (%) [7]	Hourly Controlled VOC Emissions (lb/hr)[4]	Annual Controlled VOC Emissions (tpy)[5]	Hourly Controlled CO_2 Emissions (lb/hr) [4]	Annual Controlled CO_2 Emissions (tpy) [5]	Hourly Controlled CH_4 Emissions (lb/hr) [4]	Annual Controlled CH_4 Emissions (tpy) [5]	Hourly Controlled CO_2e Emissions (lb/hr) [6]	Annual Controlled CO_2e Emissions (tpy) [6]
Valves	Gas/Vapor	2,410	97	0.047	0.207	0.0	0.00	0.7	2.90	16.6	72.5
Flanges	Gas/Vapor	4,691	97	8.0E-03	0.035	0.0	0.00	0.11	0.49	2.8	12.2
Compressor Seals	Gas/Vapor	19	95	1.2E-03	5.3E-03	0.0	0.00	0.02	0.07	0.4	1.9
Pumps	Light Liquid [8]	6	93	1.5E-04	6.4E-04	0.0	0.00	0.002	0.01	0.05	0.2
Connectors	Gas/Vapor	220	97	1.9E-04	8.4E-04	0.0	0.00	2.7E-03	0.012	0.067	0.29
Acid Gas Flanges	Gas/Vapor	50	97	9.0E-06	4.0E-05	1.2E-03	0.005	1.2E-04	0.001	0.004	0.02
Refrigerant Flanges	Gas/Vapor	370	97	9.5E-03	4.2E-02	0.0	0.00	0.0	0.00	0.0	0.00
Feed Gas Flanges	Gas/Vapor	2429	0	1.4E-01	6.0E-01	0.0	0.00	1.929	8.45	48.23	211.2
TOTAL		7,346		0.204	0.89	0.00	0.01	2.72	11.94	68.1	298.4

[1] Component Counts are based on engineering design plans for the project.

[2] Leak emission factors are from EPA document EPA-453/R-95-017; November, 1995, Table 2-4, for total organic compound emissions, and converted to lb/hr/component as presented in TCEQ.

[3] Vapor components weight fractions are from estimated gas analysis provided by NFE.

[4] Emissions (lb/hr) = Emission factor (lb/hr/component) x Equipment Count x Constituent Wt % x (1 - control efficiency)

[5] Emissions (tpy) = Emissions (lb/hr/) x Annual Hours of Operation (hr/yr) / 2,000 (lb/ton)

[6] CO_2e emissions assume a global warming potential (GWP) of 1 for CO2, and 25 for CH4.

[7] Control efficiencies based on TCEQ Technical Guidance Document - Control Efficiencies for TCEQ Leak Detection and Repair Programs (Revised 07/11 (APDG 6129v2). Reduction credit for LDAR program 28 MID with AVO.

[8] CH_4 and CO_2 weight percent in liquid phase assumed to be the same as vapor phase

[9] Acid gas VOC and CH4 content conservatively based upon maximum flash case; CO2 content conservatively based upon normal flash case.

[10] Refrigerant is a mixture of ethane, propane, and i-pentane

LNG Composition

Vapor Component		Mole % [1]	Molecular Weight (lb/lb mole)	Average Molar Mass (lb/lbmole) [2]	Weight % [3]
Nitrogen	N2	0.080	28.02	0.0224	0.1281
Carbon Dioxide	CO2	0.005	44.01	0.0022	0.0126
Methane	CH4	92.345	16.04	14.8121	84.6730
Ethane	C2H6	5.000	30.07	1.5035	8.5947
Propane	C3H8	2.500	44.10	1.1025	6.3024
i-Butane	iC4H10	0.000	58.12	0.0000	0.0000
n-Butane	nC4H10	0.000	58.12	0.0000	0.0000
i-Pentane	iC5H12	0.035	72.15	0.0253	0.1444
n-Pentane	nC5H12	0.035	72.15	0.0253	0.1444
n-Hexane	nC6H14	0.000	86.18	0.0000	0.0000
Benzene	C6H6	0.000	78.11	0.0001	0.0004
n-Heptane (C7)	nC7H16	0.000	100.20	0.0000	0.0000
n-Octane (C8)	nC8H18	0.000	114.23	0.0000	0.0000
	Total	**100.000**		17.49	100
			VOC Wt %		6.5916
			HAP Wt %		0.0004
				Mol. Wt.:	16.63 kg/kmol
				HHV:	1041.5 Btu/scf
				LHV:	940 Btu/scf

Table F-26: Project-Wide Stationary Source Speciated HAP Emissions

Pollutant	NG turbines (lb/MMBtu)[b]	NG boilers (lb/MMBtu)[b]	NG Engines (lb/MMBtu)[b]	Sm. Diesel Engines (lb/MMBtu)[b]	Lg. Diesel Engines (lb/MMBtu)[b]	Oil Boilers (lb/MMBtu)[b]	FLNG Compressor Turbines	FLNG Power Turbines	FLNG Acid Gas TOX	FLNG Cold Flares	FLNG Warm Flares	CAT 3516 Gen Engines	FLNG1 CAT 3512 Gen Engines	FLNG2 CAT 3512C Gen Engines	CAT C18 Gen Engines	Clarke C18 Fire Pump Engines	Clarke C32 Fire Pump Engines	FSU Generator Engine	FSU Boilers	FSU GCU	Facility Wide
	HAP Emission Factors[a]						STATIONARY SOURCES														
							MMBtu	MMBtu/hr	MMBtu/hr	MMBtu/yr	MMBtu/yr	MMBtu/hr	MMBtu/hr	MMBtu/hr	MMBtu/hr	MMBtu/hr	MMBtu/hr	MMBtu/hr	MMBtu/hr	MMBtu/hr	
							964.0	1043.7	12.1	967,431	684,445	137.0	11.1	80.8	10.9	5.0	33.1	7.8	10.7	197.4	
							tpy (all)	tpy (all)	tpy (all)	tpy (all)	tpy (all)	tpy (8 engines)	tpy (1 engine)	tpy (5 engines)	tpy (2 engines)	tpy (2 engines)	tpy (6 engines)	tpy (1 engine)	tpy (2 boilers)	tpy (1 Unit)	tpy
Organic Compounds																					
1,3-Butadiene	4.3E-07		2.67E-04	3.91E-05			0.001816	0.001966								9.8E-06					3.8E-03
2-Methylnaphthalene		2.4E-08							1.2E-06	1.1E-05	8.1E-06									3.3E-07	2.1E-05
3-Methylchloranthrene		1.8E-09							9.4E-08	8.5E-07	6.0E-07									2.5E-08	1.6E-06
7,12-Dimethylbenz(a)anthracene		1.6E-08							8.3E-07	7.6E-06	5.4E-06									2.2E-07	1.4E-05
Acenaphthene		1.8E-09	1.25E-06						9.4E-08	8.5E-07	6.0E-07									2.5E-08	1.6E-06
Acenaphthylene		2.4E-09	5.53E-06						1.2E-07	1.1E-06	8.1E-07									3.3E-08	2.1E-06
Acetaldehyde	4.0E-05		8.36E-03	7.67E-04	2.52E-05		0.168897	0.182863				1.73E-04	1.40E-05	1.02E-04	1.38E-05	1.92E-04	4.17E-05	9.78E-06			3.5E-01
Acrolein	6.4E-06		5.14E-03	9.25E-05	7.88E-06		0.027024	0.029258				5.40E-05	4.39E-06	3.18E-05	4.31E-06	2.31E-05	1.30E-05	3.06E-06			5.6E-02
Anthracene		1.8E-09							9.4E-08	8.5E-07	6.0E-07									2.51E-08	1.6E-06
Benz(a)anthracene		1.8E-09							9.4E-08	8.5E-07	6.0E-07									2.51E-08	1.6E-06
Benzene	1.2E-05	2.1E-06	4.40E-04		7.76E-04	1.55E-06	0.050669	0.054859	1.1E-04	1.0E-03	7.0E-04	5.32E-03	4.32E-04	3.14E-03	4.24E-04		1.29E-03	3.01E-04	7.27E-05	2.93E-05	1.2E-01
Benzo(a)pyrene		1.2E-09	4.15E-07						6.2E-08	5.7E-07	4.0E-07									1.67E-08	1.1E-06
Benzo(b)fluoranthene		1.8E-09	1.66E-07						9.4E-08	8.5E-07	6.0E-07									2.51E-08	1.6E-06
Benzo(g,h,i)perylene		1.2E-09	4.14E-07						6.2E-08	5.7E-07	4.0E-07									1.67E-08	1.1E-06
Benzo(k)fluoranthene		1.8E-09							9.4E-08	8.5E-07	6.0E-07									2.51E-08	1.6E-06
Chrysene		1.8E-09	6.93E-07						9.4E-08	8.5E-07	6.0E-07									2.51E-08	1.6E-06
Dibenzo(a,h)anthracene		1.2E-09							6.2E-08	5.7E-07	4.0E-07									1.67E-08	1.1E-06
Dichlorobenzene		1.2E-06							6.2E-05	5.7E-04	4.0E-04									1.67E-05	1.1E-03
Ethylbenzene	3.2E-05		3.97E-05			4.61E-07	0.135118	0.146290											2.16E-05		2.8E-01
Fluoranthene		2.9E-09	1.11E-06						1.6E-07	1.4E-06	1.0E-06									4.18E-08	2.6E-06
Fluorene		2.7E-09	5.67E-06						1.5E-07	1.3E-06	9.4E-07									3.90E-08	2.5E-06
Formaldehyde	7.1E-04	7.4E-05	5.28E-02	1.18E-03	7.89E-05	2.39E-04	2.997930	3.245819	3.9E-03	3.6E-02	2.5E-02	5.40E-04	4.39E-05	3.19E-04	4.31E-05	2.95E-04	1.31E-04	3.06E-05	1.12E-02	1.04E-03	6.32E+00
Hexane		1.8E-03	1.11E-03						9.4E-02	8.5E-01	6.0E-01									2.51E-02	1.6E+00
Indeno(1,2,3-cd)pyrene		1.8E-09							9.4E-08	8.5E-07	6.0E-07									2.51E-08	1.6E-06
Naphthalene	1.3E-06	6.0E-07	7.44E-05	8.48E-05		8.19E-06	0.005489	0.005943	3.2E-05	2.9E-04	2.0E-04					2.12E-05			3.84E-04	8.50E-06	1.2E-02
PAH	2.2E-06		2.69E-05	1.68E-04	2.12E-04	4.39E-07	0.009289	0.010057				1.45E-03	1.18E-04	8.56E-04	1.16E-04	4.20E-05	3.51E-04	8.23E-05	2.06E-05		2.2E-02
Phenanathrene		1.7E-08	1.04E-05						8.8E-07	8.1E-06	5.7E-06									2.37E-07	1.5E-05
Propylene oxide	2.9E-05						0.122451	0.132576													2.6E-01
Pyrene		4.9E-09	1.36E-06						2.6E-07	2.4E-06	1.7E-06									6.97E-08	4.4E-06
Toluene	0.00013	3.3E-06	4.08E-04		2.81E-04	4.49E-05	0.548917	0.594305	1.8E-04	1.6E-03	1.1E-03	1.92E-03	1.56E-04	1.14E-03	1.54E-04		4.65E-04	1.09E-04	2.11E-03	4.74E-05	1.15E+00
Xylenes	6.4E-05		1.84E-04	2.85E-04	1.93E-04	7.90E-07	0.270236	0.292581				1.32E-03	1.07E-04	7.80E-04	1.05E-04	7.12E-05	3.20E-04	7.49E-05	3.70E-05		5.7E-01
Metals/Inorganics[d]																					
Arsenic		2.0E-07				4.00E-06													1.9E-04	2.8E-06	1.9E-04
Beryllium		1.2E-08				3.00E-06													1.4E-04	1.7E-07	1.4E-04
Cadmium		1.1E-06				3.00E-06													1.4E-04	1.5E-05	1.6E-04
Chromium		1.4E-06				3.00E-06													1.4E-04	2.0E-05	1.6E-04
Cobalt		8.2E-08																		1.2E-06	1.2E-06
Lead		4.9E-07				9.00E-06													4.2E-04	7.0E-06	4.3E-04
Manganese		3.7E-07				6.00E-06													2.8E-04	5.3E-06	2.9E-04
Mercury		2.5E-07				3.00E-06													1.4E-04	3.6E-06	1.4E-04
Nickel		2.1E-06				3.00E-06													1.4E-04	2.9E-05	1.7E-04
Selenium		2.4E-08				1.50E-05													7.0E-04	3.3E-07	7.0E-04
HAP TOTALS , TPY							**4.34**	**4.70**	**0.10**	**0.89**	**0.63**	**1.1E-02**	**8.8E-04**	**6.4E-03**	**8.6E-04**	**6.5E-04**	**2.6E-03**	**6.1E-04**	**1.6E-02**	**2.6E-02**	**10.7**

[a] HAP emission factors are from AP-42.

Table F-26: Project-Wide Stationary Source Speciated HAP Emissions

							STATIONARY SOURCES														
							FLNG Compressor Turbines	FLNG Power Turbines	FLNG Acid Gas TOX	FLNG Cold Flares	FLNG Warm Flares	CAT 3516 Gen Engines	FLNG1 CAT 3512 Gen Engines	FLNG2 CAT 3512C Gen Engines	CAT C18 Gen Engines	Clarke C18 Fire Pump Engines	Clarke C32 Fire Pump Engines	FSU Generator Engine	FSU Boilers	FSU GCU	Facility Wide
							MMBtu	MMBtu/hr	MMBtu/hr	MMBtu/yr	MMBtu/yr	MMBtu/hr	MMBtu/hr	MMBtu/hr	MMBtu/hr	MMBtu/hr	MMBtu/hr	MMBtu/hr	MMBtu/hr	MMBtu/hr	
Pollutant	HAP Emission Factors[a]						964.0	1043.7	12.1	967,431	684,445	137.0	11.1	80.8	10.9	5.0	33.1	7.8	10.7	197.4	
	NG turbines (lb/MMBtu)[b]	NG boilers (lb/MMBtu)[b]	NG Engines (lb/MMBtu)[b]	Sm. Diesel Engines (lb/MMBtu)[b]	Lg. Diesel Engines (lb/MMBtu)[b]	Oil Boilers (lb/MMBtu)[b]	tpy (all)	tpy (all)	tpy (all)	tpy (all)	tpy (all)	tpy (8 engines)	tpy (1 engine)	tpy (5 engines)	tpy (2 engines)	tpy (2 engines)	tpy (6 engines)	tpy (1 engine)	tpy (2 boilers)	tpy (1 Unit)	tpy

[b] Emission factors for metals were converted from AP-42 units (lb/1000 gal of distillate oil) to lb/MMBtu by dividing by a heat content of 138 MMBtu/1000 gal.

Table F-27: HAP Emission Factors for Natural Gas Fired Combustion Turbines

Pollutant[a]	Emission Factor (lb/MMBtu)
1,3-Butadiene[b]	< 4.3E-07
Acetaldehyde	4.0E-05
Acrolein	6.4E-06
Benzene	1.2E-05
Ethylbenzene	3.2E-05
Formaldehyde	7.1E-04
Naphthalene	1.3E-06
PAH	2.2E-06
Propylene oxide[b]	< 2.9E-05
Toluene	1.3E-04
Xylenes	6.4E-05

Total for substances identified as HAP	1.03E-03

[a] Emission factors for organic compounds are from AP-42 Table 3.1-3 (04/00), for natural gas fired stationary gas turbines, except as noted in notes 2 and 3 below. These compounds are specifically listed as a "Hazardous Air Pollutant" (HAP) in the Clean Air Act, or a component of Polycyclic Organic Matter, which is also listed as a HAP.
[b] Pollutants listed with a "<" were below the detection limit; however, the listed value is used for emission calculations.

Table F-28: HAP Emission Factors for Small Stationary Diesel Engines (≤600 hp)

Pollutant	Emission Factor (lb/MMBtu)	Source (AP-42 Table)
Organic Compounds		
Xylenes[b]	2.85E-04	3.3-2
Propylene	2.58E-03	3.3-2
1,3-Butadiene[b]	< 3.91E-05	3.3-2
Formaldehyde[b]	1.18E-03	3.3-2
Acetaldehyde[b]	7.67E-04	3.3-2
Acrolein[b]	< 9.25E-05	3.3-2
PAH		
Naphthalene[b]	8.48E-05	3.3-2
Acenaphthylene[b]	< 5.06E-06	3.3-2
Acenaphthene[b]	1.42E-06	3.3-2
Fluorene[b]	2.92E-05	3.3-2
Phenanthrene[b]	2.94E-05	3.3-2
Anthracene[b]	1.87E-06	3.3-2
Fluoranthene[b]	7.61E-06	3.3-2
Pyrene[b]	4.78E-06	3.3-2
Benz(a)anthracene[b]	1.68E-06	3.3-2
Chrysene[b]	3.53E-07	3.3-2
Benzo(b)fluoranthene[b]	< 9.91E-08	3.3-2
Benzo(k)fluoranthene[b]	< 1.55E-07	3.3-2
Benzo(a)pyrene[b]	< 1.88E-07	3.3-2
Indeno(1,2,3-cd)pyrene[b]	< 3.75E-07	3.3-2
Dibenz(a,h)anthracene[b]	< 5.83E-07	3.3-2
Benzo(g,h,l)perylene[b]	< 4.89E-07	3.3-2
TOTAL PAH	1.68E-04	

Total for substances identified as HAP	2.53E-03

Discussion: The emission factors for individual organic compounds shown here are from the U.S. Environmental Protection Agency (EPA), "Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources" (AP-42), Section 3.3 for "Gasoline and Diesel Industrial Engines", rev. 10/96. Emission factors prefaced with a "<" are based on method detection limits. Section 3.3 of AP-42 does not provide emission factors for metals and inorganics from diesel engines.

[a] Pollutants listed with a "<" were below the detection limit; however, the listed value is used for emission calculations.
[b] Specifically listed as a "Hazardous Air Pollutant" (HAP) in the Clean Air Act, or a component of Polycyclic Organic Matter, which is also listed as a HAP.
[c] Emission factors for metals were converted from AP-42 units (lb/1000 gal of residual oil) to lb/MMBtu by dividing by a heat content of 150 MMBtu/1000 gal.
[d] Chloride and fluoride are included in the HAP total, based on the assumption that the predominant forms emitted are hydrogen chloride and hydrogen fluoride (both of which are listed HAP).
[e] Total calculated using the TOTAL PAH emission factor instead of factors for individual PAH.

Table F-29: HAP Emission Factors for Large Stationary Diesel Engines (>600 hp)

Pollutant		Emission Factor (lb/MMBtu)[a]	Emission Factor Rating	Source (AP-42 Table)
Organic Compounds				
Benzene[b]		7.76E-04	E	3.4-3
Toluene[b]		2.81E-04	E	3.4-3
Xylene[b]		1.93E-04	E	3.4-3
Methane		8.10E-03	E	3.4-1
Propylene		2.79E-03	E	3.4-3
Formaldehyde[b]		7.89E-05	E	3.4-3
Acetaldehyde[b]		2.52E-05	E	3.4-3
Acrolein[b]		7.88E-06	E	3.4-3
PAH				
Naphthalene[b]		1.30E-04	E	3.4-4
Acenaphthylene[b]		9.23E-06	E	3.4-4
Acenaphthene[b]		4.68E-06	E	3.4-4
Fluorene[b]		1.28E-05	E	3.4-4
Phenanthrene[b]		4.08E-05	E	3.4-4
Anthracene[b]		1.23E-06	E	3.4-4
Fluoranthene[b]		4.03E-06	E	3.4-4
Pyrene[b]		3.71E-06	E	3.4-4
Benz(a)anthracene[b]		6.22E-07	E	3.4-4
Chrysene[b]		1.53E-06	E	3.4-4
Benzo(b)fluoranthene[b]		1.11E-06	E	3.4-4
Benzo(k)fluoranthene[b]	<	2.18E-07	E	3.4-4
Benzo(a)pyrene[b]	<	2.57E-07	E	3.4-4
Indeno(1,2,3-cd)pyrene[b]	<	4.14E-07	E	3.4-4
Dibenz(a,h)anthracene[b]	<	3.46E-07	E	3.4-4
Benzo(g,h,l)perylene[b]	<	5.56E-07	E	3.4-4
TOTAL PAH	<	2.12E-04	E	3.4-4

Total for substances identified a	<	1.57E-03

Discussion: The emission factors for individual organic compounds shown here are from the U.S. Environmental Protection Agency (EPA), "Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources" (AP-42), Section 3.4 for "Large Stationary Diesel and All Stationary Dual-fuel Engines", rev. 10/96. Emission factors prefaced with a "<" are based on method detection limits. Section 3.4 of AP-42 does not provide emission factors for metals and inorganics from diesel engines.

[a] Pollutants listed with a "<" were below the detection limit; however, the listed value is used for emission calculations.
[b] Specifically listed as a "Hazardous Air Pollutant" (HAP) in the Clean Air Act, or a component of Polycyclic Organic Matter, which is also listed as a HAP.
[c] Emission factors for metals were converted from AP-42 units (lb/1000 gal of residual oil) to lb/MMBtu by dividing by a heat content of 150 MMBtu/1000 gal.
[d] Chloride and fluoride are included in the HAP total, based on the assumption that the predominant forms emitted are hydrogen chloride and hydrogen fluoride (both of which are listed HAP).

Table F-30: HAP Emission Factors for Natural Gas Engines

Pollutant		Emission Factor (lb/MMBtu)[a]	Emission Factor Rating	Source (AP-42 Table)
Organic Compounds				
1,1,2,2-Tetrachloroethane	<	4.00E-05	E	3.2-2
1,1,2-Trichloroethane	<	3.18E-05	E	3.2-2
1,3-Butadiene		2.67E-04	D	3.2-2
1,3-Dichloropropene	<	2.64E-05	E	3.2-2
2-Methylnaphthalene		3.32E-05	C	3.2-2
2,2,4-Trimethylpentane		2.50E-04	C	3.2-2
Acenaphthene		1.25E-06	C	3.2-2
Acenaphthylene		5.53E-06	C	3.2-2
Acetaldehyde		8.36E-03	A	3.2-2
Acrolein		5.14E-03	A	3.2-2
Benzene		4.40E-04	A	3.2-2
Benzo(b)fluoranthene		1.66E-07	D	3.2-2
Benzo(e)pyrene		4.15E-07	D	3.2-2
Benzo(g,h,i)perylene		4.14E-07	D	3.2-2
Biphenyl		2.12E-04	D	3.2-2
Carbon Tetrachloride	<	3.67E-05	E	3.2-2
Chlorobenzene	<	3.04E-05	E	3.2-2
Chloroform	<	2.85E-05	E	3.2-2
Chrysene		6.93E-07	C	3.2-2
Ethylbenzene		3.97E-05	B	3.2-2
Ethylene Dibromide	<	4.43E-05	E	3.2-2
Fluoranthene		1.11E-06	C	3.2-2
Fluorene		5.67E-06	C	3.2-2
Formaldehyde		5.28E-02	A	3.2-2
Methanol		2.50E-03	B	3.2-2
Methylene Chloride		2.00E-05	C	3.2-2
n-Hexane		1.11E-03	C	3.2-2
Naphthalene		7.44E-05	C	3.2-2
PAH		2.69E-05	D	3.2-2
Phenanthrene		1.04E-05	D	3.2-2
Phenol		2.40E-05	D	3.2-2
Pyrene		1.36E-06	C	3.2-2
Styrene	<	2.36E-05	E	3.2-2
Tetrachloroethane		2.48E-06	D	3.2-2
Toluene		4.08E-04	B	3.2-2
Vinyl Chloride		1.49E-05	C	3.2-2
Xylene		1.84E-04	B	3.2-2

Total for substances identified as HAP[e]	<	7.22E-02

Discussion: The emission factors for individual organic compounds shown here are from the U.S. Environmental Protection Agency (EPA), "Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources" (AP-42), Section 3.2 for "Natural Gas-fired Reciprocating Engines", rev. 07/00 for 4-stroke lean burn engines. Emission factors prefaced with a "<" are based on method detection limits. Section 3.2 of AP-42 does not provide emission factors for metals and inorganics from gas fired engines.

[a] HAP listed with a "<" were below the detection limit; however, the listed value is used for emission calculations.

Table F-31: HAP Emission Factors for Distillate Oil Combustion (Boilers)

Pollutant	Emission Factor (lb/1000 gal)[a]	(lb/MMBtu)[a]
Organic Compounds		
Benzene[b]	2.14E-04	1.55E-06
Ethylbenzene[b]	6.36E-05	4.61E-07
Formaldehyde[b]	3.30E-02	2.39E-04
Naphthalene[b]	1.13E-03	8.19E-06
1,1,1-Trichloroethane[b]	2.36E-04	1.71E-06
Toluene[b]	6.20E-03	4.49E-05
o-Xylene[b]	1.09E-04	7.90E-07
Acenaphthene[b]	2.11E-05	1.53E-07
Acenaphthylene[b]	2.53E-07	1.83E-09
Anthracene[b]	1.22E-06	8.84E-09
Benz(a)anthracene[b]	4.01E-06	2.91E-08
Benzo(b,k)fluoranthene[b]	1.48E-06	1.07E-08
Benzo(g,h,i)perylene[b]	2.26E-06	1.64E-08
Chrysene[b]	2.38E-06	1.72E-08
Dibenzo(a,h)anthracene[b]	1.67E-06	1.21E-08
Fluoranthene[b]	4.8E-06	3.51E-08
Fluorene[b]	4.5E-06	3.24E-08
Indeno(1,2,3-cd)pyrene[b]	2.1E-06	1.55E-08
Phenanathrene[b]	1.1E-05	7.61E-08
Pyrene[b]	4.3E-06	3.08E-08
OCDD[b]	3.1E-09	2.25E-11
Metals/Inorganics		
Arsenic[b]		4.00E-06
Beryllium[b]		3.00E-06
Cadmium[b]		3.00E-06
Chromium[b]		3.00E-06
Lead[b]		9.00E-06
Manganese[b]		6.00E-06
Mercury[b]		3.00E-06
Nickel[b]		3.00E-06
Selenium[b]		1.50E-05

Total for substances identified as HAP	4.1E-02	3.5E-04

Discussion: The emission factors for individual organic compounds and metals shown here are from the U.S. Environmental Protection Agency (EPA), "Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources" (AP-42), Section 1.3 for "Fuel Oil Combustion" (external), Tables 1.3-9 and 1.3-10, rev. 05/10.

[a] Conversion from lb/1000 gal to lb/MMBtu based on fuel heat content of 138,000 Btu/gal.

[b] Specifically listed as a "Hazardous Air Pollutant" (HAP) in the Clean Air Act, or a component of Polycyclic Organic Matter, which is also listed as a HAP.

Table F-32: HAP Emission Factors for Natural Gas Combustion (Boilers)

Pollutant		Emission Factor (lb/10^6 scf)[a]		Emission Factor (lb/10^6 Btu)[a]	Emission Factor Rating	Source (AP-42 Table)
Organic Compounds						
2-Methylnaphthalene[b]		2.4E-05		2.4E-08	D	1.4-3
3-Methylchloranthrene[b]	<	1.8E-06	<	1.8E-09	E	1.4-3
7,12-Dimethylbenz(a)anthracene[b]	<	1.6E-05	<	1.6E-08	E	1.4-3
Acenaphthene[b]	<	1.8E-06	<	1.8E-09	E	1.4-3
Acenaphthylene[b]	<	2.4E-06	<	2.4E-09	E	1.4-3
Anthracene[b]	<	1.8E-06	<	1.8E-09	E	1.4-3
Benz(a)anthracene[b]	<	1.8E-06	<	1.8E-09	E	1.4-3
Benzene[b]		2.1E-03		2.1E-06	B	1.4-3
Benzo(a)pyrene[b]	<	1.2E-06	<	1.2E-09	E	1.4-3
Benzo(b)fluoranthene[b]	<	1.8E-06	<	1.8E-09	E	1.4-3
Benzo(g,h,i)perylene[b]	<	1.2E-06	<	1.2E-09	E	1.4-3
Benzo(k)fluoranthene[b]	<	1.8E-06	<	1.8E-09	E	1.4-3
Butane		2.1E+00		2.1E-03	E	1.4-3
Chrysene[b]	<	1.8E-06	<	1.8E-09	E	1.4-3
Dibenzo(a,h)anthracene[b]	<	1.2E-06	<	1.2E-09	E	1.4-3
Dichlorobenzene[b]		1.2E-03		1.2E-06	E	1.4-3
Ethane		3.1E+00		3.0E-03	E	1.4-3
Fluoranthene[b]		3.0E-06		2.9E-09	E	1.4-3
Fluorene[b]		2.8E-06		2.7E-09	E	1.4-3
Formaldehyde[b]		7.5E-02		7.4E-05	B	1.4-3
Hexane[b]		1.8E+00		1.8E-03	E	1.4-3
Indeno(1,2,3-cd)pyrene[b]	<	1.8E-06	<	1.8E-09	E	1.4-3
Methane		2.3E+00		2.3E-03	B	1.4-2
Naphthalene[b]		6.1E-04		6.0E-07	E	1.4-3
Pentane		2.6E+00		2.5E-03	E	1.4-3
Phenanathrene[b]		1.7E-05		1.7E-08	D	1.4-3
Propane		1.6E+00		1.6E-03	E	1.4-3
Pyrene[b]		5.0E-06		4.9E-09	E	1.4-3
Toluene[b]		3.4E-03		3.3E-06	C	1.4-3
Total for substances identified as HAP	**<**	**1.9E+00**	**<**	**1.9E-03**		

<u>Discussion</u>: The emission factors for individual organic compounds and metals shown here are from the U.S. Environmental Protection Agency (EPA), "Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources" (AP-42), Section 1.4 for "Natural Gas Combustion" (external), rev. 7/98.

[a] Factors are converted from lb/10^6 scf to lb/MMBtu (HHV) by dividing by 1,020 Btu/scf, as per EPA. Pollutants listed with a "<" were below the detection limit; however, the listed value is used for emission calculations.
[b] Specifically listed as a "Hazardous Air Pollutant" (HAP) in the Clean Air Act, or a component of Polycyclic Organic Matter, which is also listed as a HAP.

Table F-33: Composition Data for Feed Gas and LNG

Component	Formula	Molecular Weight (kg/kgmol)	Feed Gas (Design) Mole %	LNG to Storage Mole %
Nitrogen	N2	28.02	0.4001	0.080
Carbon Dioxide	CO2	44.01	1.1240	0.005
Methane	CH4	16.04	96.3540	92.345
Ethane	C2H6	30.07	1.7651	5.000
Propane	C3H8	44.10	0.1828	2.500
i-Butane	iC4H10	58.12	0.0406	0.000
n-Butane	nC4H10	58.12	0.0406	0.000
i-Pentane	iC5H12	72.15	0.0203	0.035
n-Pentane	nC5H12	72.15	0.0102	0.035
n-Hexane	nC6H14	86.18	0.0325	0.000
n-Heptane	nC7H16	100.20	0.0102	0.000
n-Octane	nC8H18	114.23	0.0061	0.000
n-Nonane	nC9H20	128.26	0.0000	0.000
n-Decane	nC10H22	142.28	0.0020	0.000
Benzene	C6H6	78.11	0.0075	0.0001
Toluene	C7H8	92.14	0.0030	0.0000
Xylene	C8H10	106.16	0.0010	0.0000
		Total	**100.000**	**100.000**
		Mol. Wt.	**17.02 kg/kmol**	**16.63 kg/kmol**
		HHV	**1,025 Btu/scf**	**1,041.5 Btu/scf**
		LHV	**926 Btu/scf**	**940 Btu/scf**

Notes:
1) Mole fractions, average molecular weight, HHV, and LHV for LNG are taken from NFE FLNG Executive Summary.

ATTACHMENT G

COMBUSTION TURBINE BACT ANALYSIS

1.1 GE LM6000PF COMBUSTION TURBINE

1.1.1 NO_X

In a combustion process, NO_x is formed during the combustion of fuel and is generally classified as either thermal NO_x or fuel-related NO_x. Thermal NO_x results when atmospheric N_2 is oxidized at high temperatures to produce nitric oxide (NO), NO_2, and other NO_x. The major factors influencing the formation of thermal NO_x are peak flame temperatures, availability of O_2 at peak flame temperatures, and residence time within the combustion zone. Fuel-related NO_x is formed from the oxidation of chemically bound nitrogen in the fuel. Fuel-related NO_x is generally minimal for natural gas combustion; therefore, NO_x formation from combustion of natural gas is predominantly due to thermal NO_x formation.

Reduction in thermal NO_x formation can be achieved using combustion controls, and flue gas treatment can further reduce NO_x emissions to the atmosphere. Available combustion controls include water or steam injection and low-emission combustors. Modern combustion turbines generally utilize DLN combustors for natural gas firing where the natural gas and air are pre-mixed prior to combustion. DLN combustors are designed to operate below the stoichiometric air-to-fuel ratio, thereby reducing thermal NO_x formation within the combustion chamber by reducing peak flame temperatures.

1.1.1.1 Step 1: Identification of Control Technology Options

Process Modifications

The process is the proposed GE LM6000PF simple-cycle combustion turbine. A modification to the process would be a change in the combustion turbine design to limit the NO_x emissions from the unit. The Project is proposing to utilize DLN combustors to minimize thermal NO_x formation. A process modification available for small combustion turbines is catalytic combustion. Kawasaki markets combustion turbines equipped with catalytic combustors named K-Lean™ (formerly XONON).

Add-on Controls

Available add-on controls to reduce NO_x from combustion sources include the following:

- *DLN Combustion*: Turbine vendors offer what is known as lean pre-mix combustors for natural gas firing, which limit NO_x formation by reducing peak flame temperatures. DLN is generally used in combination with SCR.
- *Water or Steam Injection*: H_2O or steam injection has been historically used for both natural gas- and oil-fired turbines, but for new turbines, H_2O or steam injection is generally only used for liquid fuel firing. H_2O or steam injection is less effective than DLN, but DLN combustion cannot be used for liquid fuels.
- *SNCR*: This is selective non-catalytic reduction technology using ammonia ("NH_3") or urea as a reagent that is injected into the hot exhaust gases. SNCR is widely used as a retrofit technology for steam-generating boilers but has never been applied to control NO_x emissions from simple-cycle turbines.
- *EMx*™: This is an oxidation/absorption technology using hydrogen (H_2) or methane (CH_4) as a reactant.
- *NSCR*: This is a non-selective catalytic reduction technology without reagents to reduce NO_X emissions NSCR is used in rich-burn internal combustion engines and is effective only in a fuel-rich environment where the exhaust gas is nearly depleted of oxygen.
- *SCR*: This is a catalytic reduction technology using NH_3 as a reagent that has been successfully demonstrated on simple-cycle turbines. SCR is widely recognized as the most stringent available control technology for NO_x emissions from simple-cycle turbines.

1.1.1.2 Step 2: Identification of Technically Infeasible Control Technology Options

Kawasaki was the only manufacturer that offered K-Lean™ catalytic combustors. This technology has never been employed on compressor or power generating turbines and a review of Kawasaki's website indicates that this technology may no longer be offered for sale. Therefore, K-Lean™ was determined to be technically infeasible for the Project.

For new combustion turbines, water or steam injection is less effective than DLN in reducing NO_X formation. Water or steam injection cannot be used in tandem with DLN combustion. Since water or steam injection would not lower emissions below those achieved by DLN, they were determined to be technically infeasible for the Project.

SNCR and EMx™ were determined to be not technically feasible. SNCR requires an exhaust gas temperature between 1,600°F and 2,100°F and typically achieves NO_x reductions of 50% or less. The exhaust gas temperature from the GE LM6000PF combustion turbines will be less than 1000°F and therefore, SNCR is not technically feasible. EMx™ utilizes a catalyst that is coated with potassium carbonate to react with NO_x to form CO_2, potassium nitrite and potassium nitrate; H_2 is used to regenerate the catalyst when it becomes saturated with the products of reaction. The maximum operating temperature range for EMx™ is 750°F with an optimal range between 500°F - 700°F. The exhaust gas temperature from the GE LM6000PF combustion turbines will be greater than 900°F and therefore, EMx™ would require exhaust cooling. Unlike SCR, which is a passive reactor with a single reagent (NH_3), EMx™ is a complicated technology with numerous moving parts and multiple sections that are on or off-line at any given time due to the need to regenerate the catalyst with H_2 in an O_2-free environment. This complexity reduces the reliability of EMx™ as compared to SCR. EMx™ technology has never been installed on a simple-cycle combustion turbine. Furthermore, a search of publicly available sources of information did not identify a current EMx™ vendor. For these reasons, EMx™ was eliminated as technically infeasible for the Project.

NSCR requires that the exhaust gas contain very low levels of oxygen. Combustion turbines operate with very high levels of excess air and oxygen concentrations in the exhaust are typically near 15 percent. NSCR cannot operate at such high oxygen levels and therefore NSCR was eliminated as technically infeasible.

SCR is an add-on control technology that involves injection of ammonia ("NH_3") into the exhaust gas upstream of a catalyst bed. On the catalyst surface, NH_3 reacts with the NO_X (NO and NO_2) in the flue gas to form N_2 and H_2O per the following chemical reactions:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$

$$8NH_3 + 6NO_2 \rightarrow 7N_2 + 12H_2O$$

The SCR catalyst's active surface is usually a noble metal (platinum), base metal (titanium or vanadium) or a zeolite-based material. NH_3 is injected and mixed into the exhaust gas upstream of the catalyst bed in greater than stoichiometric amounts to achieve optimal conversion of NO_X. Excess NH_3 that is not reacted in the catalyst bed is emitted through the stack and is referred to as "ammonia slip." A critical factor that affects the performance of an SCR system is the operating temperature. The optimal temperature range for standard base metal catalysts is between 450°F and 850°F. At temperatures above 850°F, permanent damage to the catalyst can occur and at temperature below 600°F the effectiveness of SCR begins to drop.

An undesirable side effect of the use of SCR systems is the potential for formation of ammonium bisulfate and ammonium sulfate, referred to as ammonium salts. These salts are reaction products of sulfur trioxide (SO_3) and NH_3. Ammonium salts are corrosive and can stick to the heat exchanger surfaces, duct work or the stack at low temperatures. In addition, ammonium salts are considered $PM/PM_{10}/PM_{2.5}$ and, therefore, increase the emissions of these criteria pollutants.

SCR on simple cycle combustion turbines requires a separate housing to accommodate the catalyst and an ammonia injection grid as well as a storage tank for the ammonia. The exhaust temperature of the GE LM6000 will be approximately 950°F and would require separate tempering air systems to inject ambient air into the turbine exhaust to lower the temperature within the proper operating temperature of the SCR catalyst. These systems would require installation of significant additional ductwork. The Project's combustion turbines will be installed on offshore platforms with very limited deck space and weight limitations.

On FLNG1, the LM6000 compressor train is mounted on the forward-facing deck of the Pioneer II platform adjacent to the forward rig leg. The FLNG1 LM6000 compressor train is situated close to the platform edge such that no additional space is available for mounting the SCR equipment. The additional SCR equipment cited above would also cause the platform to exceed its design weight limit. For these reasons, SCR on the FLNG1 LM6000 compressor turbine is not technically feasible.

The FLNG2 platform can accommodate can SCR on the LM6000 combustion turbine. Accordingly, NFE will install SCR on the LM6000 combustion turbine. No offshore LNG export facilities were identified using SCR.

DLN combustors are technically feasible for the proposed combustion turbines.

1.1.1.3 Step 3: Ranking of Technically Feasible Control Technology Options

DLN combustion represents the highest level of emissions control for technically feasible control options for the FLNG1 LM6000. DLN combustion and SCR represents the highest level of emissions control for technically feasible control options for the FLNG2 LM6000.

1.1.1.4 Step 4: Evaluation of Most Effective Controls

A search of the USEPA's RBLC and available permits for similar sources was conducted to identify approved BACT NO_x limits for natural gas fired simple-cycle combustion turbines operating at LNG production facilities. The details of this review were presented in Appendix C, Table C-1 of the permit application. This review shows that numerous combustion turbines at LNG production facilities utilize DLN combustors as the sole control to meet BACT. Three land-based LNG production projects with combustion compressor turbines and one project with power generating turbines equipped with SCR operating were identified but no offshore LNG export facilities were identified using SCR on combustion turbines. Two proposed offshore LNG export facilities, Port Delfin and Lavaca Bay, proposed DLN and water injection, respectively, to meet BACT for NO_X with proposed limits of 25 parts per million by volume dry basis corrected to 15 percent oxygen (ppmvdc). As noted in Step 2, SCR is not technically feasible on the FLNG1 LM6000 turbine. Therefore, the most stringent level proposed or achieved in practice for the FLNG1 LM6000 turbine is DLN combustion. The FLNG2 LM6000 turbine will be equipped with SCR and meet an emission limit of 15 ppmvdc.

A review of emission limits in SIPs and federal regulations did not identify any NO_x emission limits for simple cycle combustion turbines that are more stringent than limits achieved in practice by DLN combustors.

1.1.1.5 Step 5: Selection of BACT

DLN combustion represents the highest level of emissions control and will be installed on all of the Project's combustion turbines. The lowest guaranteed NO_X emission rate was requested from the combustion turbine vendors. GE literature advertises a NO_X rate of 15 ppmvdc for the LM6000PF but this rate was not available as an emissions guarantee for the Project. The selected NO_X BACT rate for the FLNG1 GE LM6000PF is equal to the vendor specified guaranteed emission rate. The selected NO_X BACT rate for the FLNG2 GE LM6000PF is equal to the SCR vendor specified guaranteed emission rate. The selected BACT rate for each turbine is as follows:

- FLNG1 GE LM6000PF: 25 ppmvdc
- FLNG2 GE LM6000PF: 15 ppmvdc

The proposed controls represent the top level of control that is technically feasible for the Project and have been demonstrated to be achievable in practice. Pursuant to EPA guidance, an evaluation of economic and energy impacts was not conducted as the top level of control was selected.

The above rate reflects BACT during steady state operation at or above 60 percent of rated operating load. Compliance with the emission rate will be verified during initial performance testing.

Emissions during SU/SD will be limited through good operating practices to minimize the duration of SU/SD events to achieve the steady state BACT rate as quickly as possible.

1.1.2 CO

1.1.2.1 Step 1: Identification of Control Technology Options

Process Modifications

The process is the proposed combustion turbines which have inherently low CO emission rates due to their very high combustion efficiency. Emissions of CO from combustion turbines result from the incomplete combustion of organic compounds in the fuel. In an ideal combustion process, all carbon and hydrogen contained within the fuel would be oxidized to form CO_2 and water. CO emissions from the combustion turbines are limited by utilizing good combustion practices to ensure that the fuel is completely combusted. Lean pre-mix DLN combustors for natural gas firing are designed to minimize NO_X emissions which may result in a small increase in CO emissions, but current DLN combustors provide a high degree of combustion efficiency. Combustion controls are commonly used to ensure complete combustion of the fuel.

Carbon Monoxide Turndown (COTD) is a technology offered by Siemens on some of their combustion turbines to lower the minimum operating load at which the steady state CO emissions rate can be maintained.

Add-on Controls

Available add-on controls to reduce CO from combustion sources include the following:

- *Oxidation Catalyst*: An oxidation catalyst system oxidizes carbon containing compounds at lower temperatures through the use of a catalyst. An oxidation catalyst system is widely recognized as the most stringent available post-combustion control technology for CO emissions from combustion turbines. The optimum operating temperature for oxidation catalysts is generally between 700°F to 1,100°F.

Oxidation catalyst systems consist of a passive reactor composed of a grid of metal panels with a platinum catalyst. CO reduction efficiencies in the range of 80 to 90 percent are typical, although CO reduction may at times be less than these values due to the low inlet concentrations expected from the combustion turbines.

1.1.2.2 Step 2: Identification of Technically Infeasible Control Technology Options

Good combustion practices is technically feasible. NFE's engineer has reviewed the requirements for installation of an oxidation catalyst on the GE LM6000PF combustion turbines and determined that there is insufficient space to accommodate them. Therefore, oxidation catalysts are not technically feasible for these turbines.

COTD is not available for the GE LM6000PF combustion turbines. Therefore, COTD was eliminated as a technically infeasible.

1.1.2.3 Step 3: Ranking of Technically Feasible Control Technology Options

Good combustion practices is the top-ranked control option.

1.1.2.4 Step 4: Evaluation of Most Effective Controls

A search of the USEPA's RBLC and available permits for similar sources was conducted to identify approved BACT CO limits for natural gas fired simple-cycle combustion turbines operating at LNG production facilities. The details of this review were presented in Appendix C, Table C-2 of the permit application. This review shows that all but two combustion turbines at land-based LNG production facilities utilize good combustion practices as the sole control to meet BACT with limits ranging from 15 to 25 ppmvdc. No offshore LNG export facilities were identified using oxidation catalysts.

Based on this search, use of efficient combustion and an oxidation catalyst is the most stringent level of CO control for offshore combustion turbines. Therefore, the use of these controls is considered to represent the most stringent level of CO control achieved in practice.

A review of emission limits in SIPs and federal regulations did not identify any CO emission limits for simple cycle combustion turbines that are more stringent than limits achieved in practice by good combustion practices.

1.1.2.5 Step 5: Selection of BACT

The Project is proposing to use good combustion practices to meet BACT for CO emissions from the combustion turbines consistent with the BACT controls for the vast majority of combustion turbines permitted at LNG production facilities. To our knowledge, an oxidation catalyst has never been applied to a combustion turbine on floating structures and therefore this technology has not been demonstrated in practice for this type of application. Furthermore, the Project's engineers have determined that there is insufficient space to install an oxidation catalyst.

The selected BACT rate for the GE LN6000PF combustion turbine is provided below and is based upon the vendor guaranteed steady state emission rate.

- GE LM6000PF: 25 ppmvdc

The above rate reflects BACT during steady state operation at or above 60 percent of rated operating load. Compliance with the emission rate will be verified during initial performance testing.

Emissions during SU/SD will be limited through good operating practices to minimize the duration of SU/SD events to achieve the steady state BACT rate as quickly as possible.

1.1.3 VOC

1.1.3.1 Step 1: Identification of Control Technology Options

Process Modifications

Combustion turbines have inherently low VOC emission rates due to their high combustion efficiency. Emissions of VOC from the combustion turbines occur as a result of incomplete combustion of organic compounds within the fuel. In an ideal combustion process, all carbon and hydrogen contained within the fuel are oxidized to form CO_2 and water. Lean pre-mix DLN combustors for natural gas firing are designed to minimize NO_X emissions which may result in a small increase in VOC emissions, but current DLN combustors provide a high degree of combustion efficiency. Combustion controls are commonly used to ensure complete combustion of the fuel.

Add-on Controls

Available add-on controls to reduce NO_x from combustion sources include the following:

- *Oxidation Catalyst*: An oxidation catalyst system oxidizes carbon containing compounds at lower temperatures through the use of a catalyst. An oxidation catalyst system is widely recognized as the most stringent available post-combustion control technology for VOC emissions from combustion turbines. The optimum operating temperature for oxidation catalysts is generally between 700°F to 1,100°F.

An oxidation catalyst can effectively control some VOC constituents in the exhaust from combustion turbines, but the degree of removal depends on the specific VOC compounds. Short straight-chain hydrocarbons such as propane will not be effectively controlled by an oxidation catalyst, whereas longer straight-chain hydrocarbons such as hexane and partially oxidized compounds such as formaldehyde, will be highly controlled. For this reason, the vendors will not guarantee a VOC emissions reduction as the exact species of VOCs in the exhaust is not known.

1.1.3.2 Step 2: Identification of Technically Infeasible Control Technology Options

Good combustion practices is technically feasible. As noted in Section 1.1.2.2, an oxidation catalyst is not technically feasible.

1.1.3.3 Step 3: Ranking of Technically Feasible Control Technology Options

Good combustion practices is the top-ranked control option.

1.1.3.4 Step 4: Evaluation of Most Effective Controls

A search of the USEPA's RBLC and available permits for similar sources was conducted to identify approved BACT VOC limits for natural gas fired simple-cycle combustion turbines operating at LNG production facilities. The details of this review were presented in Appendix C, Table C-3 of the permit application. This review shows that all but two combustion turbines at land-based LNG production facilities utilized good combustion practices as the sole control to meet BACT with a range of limits in units of ppmvdc, lbs/MMBtu, and lb/hr. No combustion turbines located at an offshore LNG export facility were identified using oxidation catalysts.

Based on this search, use of good combustion practices is the most stringent level of VOC control for offshore combustion turbines. Therefore, this is considered the most stringent level of VOC control achieved in practice.

A review of emission limits in SIPs and federal regulations did not identify any VOC emission limits for simple cycle combustion turbines that are more stringent than limits achieved in practice by good combustion practices.

1.1.3.5 Step 5: Selection of BACT

The Project is proposing to use good combustion practices to meet BACT for VOC emissions from the combustion turbines consistent with the BACT controls for all but one LNG project. The selected BACT rate is provided below and is based upon the vendor guaranteed steady state emission rate.

- GE LM6000PF: 3 ppmvdc

The above rate reflects BACT during steady state operation at or above 60 percent of rated operating load. These rates are reflected in the vendor performance data provided in Appendix D of the application. Compliance with the emission rate will be verified during initial performance testing. A review of other recently approved LNG projects including 2018 Driftwood LNG, 2020 Lake Charles LNG, and 2016 Golden Pass LNG did not indicate any continuous compliance methods beyond initial performance testing. NFE proposes to meet the same standard as similar projects for VOC compliance which is to complete initial performance testing.

Emissions during SU/SD will be limited through good operating practices to minimize the duration of SU/SD events to achieve the steady state BACT rate as quickly as possible.

1.1.4 PM/PM_{10}/$PM_{2.5}$

1.1.4.1 Step 1: Identification of Control Technology Options

Process Modifications

The process is the combustion turbines fired with natural gas which will have inherently low PM emission rates. Emissions of PM from combustion of natural gas can occur as a result of trace inert solids contained in the fuel and products of incomplete combustion, which may agglomerate or condense to form particles. All of the PM emitted from the combustion turbines is considered to be $PM_{2.5}$. Therefore, the PM, PM_{10} and $PM_{2.5}$ emission rates are assumed to be equivalent.

Add-on Controls

This evaluation did not identify any $PM/PM_{10}/PM_{2.5}$ post-combustion control technologies available for combustion turbines. Post-combustion PM control technologies such as fabric filters (baghouses), electrostatic precipitators, and/or wet scrubbers, which are commonly used on solid-fuel and heavy oil-fueled boilers, are not available for combustion turbines since the large amount of excess air inherent to combustion turbine technology would create an unacceptable amount of backpressure for combustion turbine operation. There are no known combustion turbine facilities that are equipped with a post-combustion PM control technology.

1.1.4.2 Step 2: Identification of Technically Infeasible Control Technology Options

The only known control option for $PM/PM_{10}/PM_{2.5}$ from combustion turbines is to use clean-burning fuels and ensure good combustion practices. The project will use natural gas as the sole fuel in the combustion turbines.

1.1.4.3 Step 3: Ranking of Technically Feasible Control Technology Options

The firing of natural gas as the sole fuel and good combustion practices is the top level of technically feasible controls.

1.1.4.4 Step 4: Evaluation of Most Effective Controls

The results of the search of the RBLC and other available permits for $PM/PM_{10}/PM_{2.5}$ BACT precedents were presented in Appendix C, Table C-4 of the permit application. Based on this search, use of clean-burning fuels and good combustion practices are the most stringent available technologies for control of combustion turbine $PM_{10}/PM_{2.5}$ emissions.

A review of Table C-4 indicates that $PM/PM_{10}/PM_{2.5}$ emission limits have been expressed either in lb/hr or lb/MMBtu units. A review of the permitted $PM/PM_{10}/PM_{2.5}$ emission limits for natural gas-fueled combustion turbines shows a wide-range of values. It is important to recognize that the differences in $PM/PM_{10}/PM_{2.5}$ emission limits among various projects are mostly due to different emission guarantee philosophies of the various combustion turbine vendors and are not believed to be actual differences in the quantity of $PM/PM_{10}/PM_{2.5}$ emissions produced by the various combustion turbine models. The different emission guarantee philosophies are influenced by the overall uncertainties of the $PM/PM_{10}/PM_{2.5}$ test procedures, especially given reported difficulties in achieving test repeatability, and concerns with artifact emissions introduced by the inclusion of condensable particulate emissions in permit limits in the last decade. All of the $PM/PM_{10}/PM_{2.5}$ emission limits listed in Table C-4 are based upon good combustion practices and vendor performance emissions guarantee.

The Project is proposing BACT $PM/PM_{10}/PM_{2.5}$ limits based upon the vendor emission guarantee provided for each combustion turbine proposed for the Project. The proposed limits are well within in the range of the other $PM/PM_{10}/PM_{2.5}$ BACT limits in Table C-4.

A review of emission limits in SIPs and federal regulations did not identify any $PM/PM_{10}/PM_{2.5}$ emission limits for simple cycle combustion turbines that are more stringent than limits achieved in practice by good combustion practices.

1.1.4.5 Step 5: Selection of BACT

The Project is proposing to use the most stringent level of control, firing natural gas as the sole fuel and good combustion practices for the combustion turbines and duct burners. The selected BACT rate is provided below and is based upon the vendor guaranteed steady state emission rate at full operating load.

- GE LM6000PF: 0.010 lb/MMBtu

The above rate reflects BACT during steady state operation at or above 60 percent of rated operating load. Emissions during SU/SD will be limited through good operating practices to minimize the duration of SU/SD events to achieve the steady state BACT rate as quickly as possible.

The proposed controls represent the top level of control that is technically feasible for the Project and have been demonstrated to be achievable in practice. Pursuant to EPA guidance, an evaluation of economic and energy impacts has not been conducted. There are no unacceptable collateral environmental impacts associated with the proposed PM/PM_{10}/$PM_{2.5}$ BACT.

1.1.5 SO_2 and H_2SO_4

Emissions of SO_2 and H_2SO_4 are formed from the oxidation of sulfur in the fuel and therefore the BACT for these two pollutants has been combined.

1.1.5.1 Step 1: Identification of Control Technology Options

Process Modifications

Emissions of SO_2 and H_2SO_4 are formed from the oxidation of sulfur in the fuel. Normally, all sulfur compounds contained in the fuel will oxidize, with the vast majority initially oxidizing in the combustion turbine to SO_2 and a smaller percentage to SO_3. After being formed, SO_3 reacts with water in the exhaust to form H_2SO_4 and sulfate particulate. There are no process modifications available to reduce SO_2 and H_2SO_4 emissions from the combustion turbine.

Add-on Controls

This evaluation did not identify any post-combustion control technologies available for SO_2 and H_2SO_4 emissions from combustion turbines. Post-combustion SO_2 and H_2SO_4 control technologies, such as dry or wet scrubbers that are commonly used on solid-fuel and heavy oil-fueled boilers, are not available for combustion turbines since the large amount of excess air inherent to combustion turbine technology would create an unacceptable amount of backpressure for combustion turbine operation. Furthermore, the low concentrations of SO_2 and H_2SO_4 in the exhaust gas, typically less than 1 ppmvdc, would make further reductions very difficult, if not impossible, to achieve. A review of readily available information did not identify any combustion turbines that are equipped with post-combustion SO_2 and H_2SO_4 control technologies.

1.1.5.2 Step 2: Identification of Technically Infeasible Control Technology Options

The only known control option for SO_2 and H_2SO_4 from a combustion turbine is to use low-sulfur fuels, such as natural gas, and ensure good combustion practices.

1.1.5.3 Step 3: Ranking of Technically Feasible Control Technology Options

The firing of natural gas and BOG as the sole fuels is the only technically feasible control.

1.1.5.4 Step 4: Evaluation of Most Effective Controls

The results of the search of the RBLC and other available permits for SO_2 and H_2SO_4 BACT precedents were presented in Appendix C, Table C-5 of the permit application. This search confirms that the only SO_2 and H_2SO_4 BACT technology identified for combustion turbines is use of low-sulfur fuel (e.g., natural gas). There were no cases identified of any post-combustion controls used to control SO_2 and H_2SO_4 emissions from combustion turbines.

1.1.5.5 Step 5: Selection of BACT

The Project is proposing to use the most stringent level of control, using natural gas as the sole fuel for the combustion turbines. The Project's design is based upon a maximum sulfur content of 20 ppmv which is equivalent to an emission rate of 0.003 lb/MMBtu. The proposed BACT emission rate for H_2SO_4 is 0.00023 lb/MMBtu which reflects a 5 percent conversion of SO_2 to H_2SO_4.

Use of natural gas and BOG as the sole fuels provides the greatest level of H_2SO_4 reduction technically feasible and represents the top level of control. Pursuant to EPA guidance, an evaluation of economic and energy impacts has not been conducted. There are no unacceptable collateral environmental impacts associated with the proposed H_2SO_4 BACT.

1.2 SIEMENS SGT-400 COMBUSTION TURBINE

1.2.1 NO_X

In a combustion process, NO_x is formed during the combustion of fuel and is generally classified as either thermal NO_x or fuel-related NO_x. Thermal NO_x results when atmospheric N_2 is oxidized at high temperatures to produce nitric oxide (NO), NO_2, and other NO_x. The major factors influencing the formation of thermal NO_x are peak flame temperatures, availability of O_2 at peak flame temperatures, and residence time within the combustion zone. Fuel-related NO_x is formed from the oxidation of chemically bound nitrogen in the fuel. Fuel-related NO_x is generally minimal for natural gas combustion; therefore, NO_x formation from combustion of natural gas is predominantly due to thermal NO_x formation.

Reduction in thermal NO_x formation can be achieved using combustion controls, and flue gas treatment can further reduce NO_x emissions to the atmosphere. Available combustion controls include water or steam injection and low-emission combustors. Modern combustion turbines generally utilize DLN combustors for natural gas firing where the natural gas and air are pre-mixed prior to combustion. DLN combustors are designed to operate below the stoichiometric air-to-fuel ratio, thereby reducing thermal NO_x formation within the combustion chamber by reducing peak flame temperatures.

1.2.1.1 Step 1: Identification of Control Technology Options

Process Modifications

The process is the proposed Siemens SGT-400 simple-cycle combustion turbine. A modification to the process would be a change in the combustion turbine design to limit the NO_x emissions from the unit. The Project is proposing to utilize DLN combustors to minimize thermal NO_x formation. A process modification available for small combustion turbines is catalytic combustion. Kawasaki markets combustion turbines equipped with catalytic combustors named K-Lean™ (formerly XONON).

Add-on Controls

Available add-on controls to reduce NO_x from combustion sources include the following:

- *DLN Combustion*: Turbine vendors offer what is known as lean pre-mix combustors for natural gas firing, which limit NO_x formation by reducing peak flame temperatures. DLN is generally used in combination with SCR.
- *Water or Steam Injection*: H_2O or steam injection has been historically used for both natural gas- and oil-fired turbines, but for new turbines, H_2O or steam injection is generally only used for liquid fuel firing. H_2O or steam injection is less effective than DLN, but DLN combustion cannot be used for liquid fuels.

- *SNCR*: This is selective non-catalytic reduction technology using ammonia ("NH_3") or urea as a reagent that is injected into the hot exhaust gases. SNCR is widely used as a retrofit technology for steam-generating boilers but has never been applied to control NO_x emissions from simple-cycle turbines.
- *EMx*™: This is an oxidation/absorption technology using hydrogen (H_2) or methane (CH_4) as a reactant.
- *NSCR*: This is a non-selective catalytic reduction technology without reagents to reduce NO_X emissions NSCR is used in rich-burn internal combustion engines and is effective only in a fuel-rich environment where the exhaust gas is nearly depleted of oxygen.
- *SCR*: This is a catalytic reduction technology using NH_3 as a reagent that has been successfully demonstrated on simple-cycle turbines. SCR is widely recognized as the most stringent available control technology for NO_x emissions from simple-cycle turbines.

1.2.1.2 Step 2: Identification of Technically Infeasible Control Technology Options

Kawasaki was the only manufacturer that offered K-Lean™ catalytic combustors. This technology has never been employed on compressor or power generating turbines and a review of Kawasaki's website indicates that this technology may no longer be offered for sale. Therefore, K-Lean™ was determined to be technically infeasible for the Project.

For new combustion turbines, water or steam injection is less effective than DLN in reducing NO_X formation. Water or steam injection cannot be used in tandem with DLN combustion. Since water or steam injection would not lower emissions below those achieved by DLN, they were determined to be technically infeasible for the Project.

SNCR and EMx™ were determined to be not technically feasible. SNCR requires an exhaust gas temperature between 1,600°F and 2,100°F and typically achieves NO_x reductions of 50% or less. The exhaust gas temperature from the Siemens SGT-400 combustion turbines will be less than 1000°F and therefore, SNCR is not technically feasible. EMx™ utilizes a catalyst that is coated with potassium carbonate to react with NO_x to form CO_2, potassium nitrite and potassium nitrate; H_2 is used to regenerate the catalyst when it becomes saturated with the products of reaction. The maximum operating temperature range for EMx™ is 750°F with an optimal range between 500°F - 700°F. The exhaust gas temperature from the Siemens SGT-400 combustion turbines will be greater than 900°F and therefore, EMx™ would require exhaust cooling. Unlike SCR, which is a passive reactor with a single reagent (NH_3), EMx™ is a complicated technology with numerous moving parts and multiple sections that are on or off-line at any given time due to the need to regenerate the catalyst with H_2 in an O_2-free environment. This complexity reduces the reliability of EMx™ as compared to SCR. EMx™ technology has never been installed on a simple-cycle combustion turbine. Furthermore, a search of publicly available sources of information did not identify a current EMx™ vendor. For these reasons, EMx™ was eliminated as technically infeasible for the Project.

NSCR requires that the exhaust gas contain very low levels of oxygen. Combustion turbines operate with very high levels of excess air and oxygen concentrations in the exhaust are typically near 15 percent. NSCR cannot operate at such high oxygen levels and therefore NSCR was eliminated as technically infeasible.

SCR is an add-on control technology that involves injection of ammonia ("NH_3") into the exhaust gas upstream of a catalyst bed. On the catalyst surface, NH_3 reacts with the NO_X (NO and NO_2) in the flue gas to form N_2 and H_2O per the following chemical reactions:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$

$$8NH_3 + 6NO_2 \rightarrow 7N_2 + 12H_2O$$

The SCR catalyst's active surface is usually a noble metal (platinum), base metal (titanium or vanadium) or a zeolite-based material. NH_3 is injected and mixed into the exhaust gas upstream of the catalyst bed in greater than stoichiometric amounts to achieve optimal conversion of NO_X. Excess NH_3 that is not reacted in the catalyst bed is emitted through the stack and is referred to as “ammonia slip.” A critical factor that affects the performance of an SCR system is the operating temperature. The optimal temperature range for standard base metal catalysts is between 450°F and 850°F. At temperatures above 850°F, permanent damage to the catalyst can occur and at temperature below 600°F the effectiveness of SCR begins to drop.

An undesirable side effect of the use of SCR systems is the potential for formation of ammonium bisulfate and ammonium sulfate, referred to as ammonium salts. These salts are reaction products of sulfur trioxide (SO_3) and NH_3. Ammonium salts are corrosive and can stick to the heat exchanger surfaces, duct work or the stack at low temperatures. In addition, ammonium salts are considered PM/PM_{10}/$PM_{2.5}$ and, therefore, increase the emissions of these criteria pollutants.

NFE’s engineer has determined that the Project’s design cannot accommodate SCR on the Siemens SGT-400 power generating turbines. The location of these turbines, near the platform’s emergency generating and fire pump engines, cannot accommodate the additional duct work, ammonia storage tanks, ammonia pumps, and catalyst enclosure for an SCR system. There is no other location on the platform to relocate the Siemens SGT-400 turbines and therefore it was determined that SCR on the Siemens SGT-400 turbines is not technically feasible.

DLN combustors are technically feasible for the proposed combustion turbines.

1.2.1.3 Step 3: Ranking of Technically Feasible Control Technology Options

DLN combustion represents the highest level of emissions control for technically feasible control options.

1.2.1.4 Step 4: Evaluation of Most Effective Controls

A search of the USEPA’s RBLC and available permits for similar sources was conducted to identify approved BACT NO_x limits for natural gas fired simple-cycle combustion turbines operating at LNG production facilities. The details of this review were presented in Appendix C, Table C-1 of the permit application. This review shows that numerous combustion turbines at LNG production facilities utilize DLN combustors as the sole control to meet BACT. Three land-based LNG production projects with combustion compressor turbines and one project with power generating turbines equipped with SCR operating were identified but no offshore LNG export facilities were identified using SCR on combustion turbines. Two proposed offshore LNG export facilities, Port Delfin and Lavaca Bay, proposed DLN and water injection, respectively, to meet BACT for NO_X with proposed limits of 25 parts per million by volume dry basis corrected to 15 percent oxygen (ppmvdc). As noted in Step 2, SCR is not technically feasible on offshore combustion turbines. Therefore, the most stringent level of control proposed or achieved in practice for an offshore combustion turbine is DLN combustion.

A review of emission limits in SIPs and federal regulations did not identify any NO_x emission limits for simple cycle combustion turbines that are more stringent than limits achieved in practice by DLN combustors.

1.2.1.5 Step 5: Selection of BACT

DLN combustion represents the highest level of emissions control and will be installed on all of the Project’s combustion turbines. The lowest guaranteed NO_X emission rate was requested from the combustion turbine vendors. The selected NO_X BACT rate for the Siemens SGT-400 is equal to the vendor specified guaranteed emission rate. The selected BACT rate for each turbine is as follows:

- Siemens SGT-400: 15 ppmvdc

The proposed controls represent the top level of control that is technically feasible and have been demonstrated to be achievable in practice. Pursuant to EPA guidance, an evaluation of economic and energy impacts was not conducted as the top level of control was selected.

The above rate reflects BACT during steady state operation at or above 50 percent of rated operating load. Compliance with the emission rate will be verified during initial performance testing.

Emissions during SU/SD will be limited through good operating practices to minimize the duration of SU/SD events to achieve the steady state BACT rate as quickly as possible.

1.2.2 CO

1.2.2.1 Step 1: Identification of Control Technology Options

Process Modifications

The process is the proposed combustion turbines which have inherently low CO emission rates due to their very high combustion efficiency. Emissions of CO from combustion turbines result from the incomplete combustion of organic compounds in the fuel. In an ideal combustion process, all carbon and hydrogen contained within the fuel would be oxidized to form CO_2 and water. CO emissions from the combustion turbines are limited by utilizing good combustion practices to ensure that the fuel is completely combusted. Lean pre-mix DLN combustors for natural gas firing are designed to minimize NO_X emissions which may result in a small increase in CO emissions, but current DLN combustors provide a high degree of combustion efficiency. Combustion controls are commonly used to ensure complete combustion of the fuel.

Carbon Monoxide Turndown (COTD) is a technology offered by Siemens on some of their combustion turbines to lower the minimum operating load at which the steady state CO emissions rate can be maintained.

Add-on Controls

Available add-on controls to reduce CO from combustion sources include the following:

- *Oxidation Catalyst*: An oxidation catalyst system oxidizes carbon containing compounds at lower temperatures through the use of a catalyst. An oxidation catalyst system is widely recognized as the most stringent available post-combustion control technology for CO emissions from combustion turbines. The optimum operating temperature for oxidation catalysts is generally between 700°F to 1,100°F.

Oxidation catalyst systems consist of a passive reactor composed of a grid of metal panels with a platinum catalyst. CO reduction efficiencies in the range of 80 to 90 percent are typical, although CO reduction may at times be less than these values due to the low inlet concentrations expected from the combustion turbines.

1.2.2.2 Step 2: Identification of Technically Infeasible Control Technology Options

Good combustion practices is technically feasible. NFE's engineer has reviewed the requirements for installation of an oxidation catalyst on the Siemens SGT-400 combustion turbines and determined that there is insufficient space to accommodate them. Therefore, oxidation catalysts are not technically feasible for these turbines.

The Siemens SGT-400 combustion turbines will be operated at steady state loads at or above 50 percent and therefore COTD is not applicable. Therefore, COTD was eliminated as a technically infeasible.

1.2.2.3 Step 3: Ranking of Technically Feasible Control Technology Options

Good combustion practices is the top-ranked control option.

1.2.2.4 Step 4: Evaluation of Most Effective Controls

A search of the USEPA's RBLC and available permits for similar sources was conducted to identify approved BACT CO limits for natural gas fired simple-cycle combustion turbines operating at LNG production facilities. The details of this review were presented in Appendix C, Table C-2 of the permit application. This review shows that all but two combustion turbines at land-based LNG production facilities utilize good combustion practices as the sole control to meet BACT with limits ranging from 15 to 25 ppmvdc. No offshore LNG export facilities were identified using oxidation catalysts.

Based on this search, use of efficient combustion is the most stringent level of CO control technically feasible for the turbines. Therefore, the use of these controls is considered to represent the most stringent level of CO control achieved in practice.

A review of emission limits in SIPs and federal regulations did not identify any CO emission limits for simple cycle combustion turbines that are more stringent than limits achieved in practice by good combustion practices.

1.2.2.5 Step 5: Selection of BACT

The Project is proposing to use good combustion practices to meet BACT for CO emissions from the combustion turbines consistent with the BACT controls for the vast majority of combustion turbines permitted at LNG production facilities. .

The selected BACT rate for each turbine is provided below and is based upon the vendor guaranteed steady state emission rate.

- Siemens SGT-400: 15 ppmvdc

The above rate reflects BACT during steady state operation at or above 50 percent of rated operating load. Compliance with the emission rate will be verified during initial performance testing.

Emissions during SU/SD will be limited through good operating practices to minimize the duration of SU/SD events to achieve the steady state BACT rate as quickly as possible.

1.2.3 VOC

1.2.3.1 Step 1: Identification of Control Technology Options

Process Modifications

Combustion turbines have inherently low VOC emission rates due to their high combustion efficiency. Emissions of VOC from the combustion turbines occur as a result of incomplete combustion of organic compounds within the fuel. In an ideal combustion process, all carbon and hydrogen contained within the fuel are oxidized to form CO_2 and water. Lean pre-mix DLN combustors for natural gas firing are designed to minimize NO_X emissions which may result in a small increase in VOC emissions, but current DLN combustors provide a high degree of combustion efficiency. Combustion controls are commonly used to ensure complete combustion of the fuel.

Add-on Controls

Available add-on controls to reduce NO_x from combustion sources include the following:

- *Oxidation Catalyst*: An oxidation catalyst system oxidizes carbon containing compounds at lower temperatures through the use of a catalyst. An oxidation catalyst system is widely recognized as the most stringent available post-combustion control technology for VOC emissions from combustion turbines. The optimum operating temperature for oxidation catalysts is generally between 700°F to 1,100°F.

An oxidation catalyst can effectively control some VOC constituents in the exhaust from combustion turbines, but the degree of removal depends on the specific VOC compounds. Short straight-chain hydrocarbons such as propane will not be effectively controlled by an oxidation catalyst, whereas longer straight-chain hydrocarbons such as hexane and partially oxidized compounds such as formaldehyde, will be highly controlled. For this reason, the vendors will not guarantee a VOC emissions reduction as the exact species of VOCs in the exhaust is not known.

1.2.3.2 Step 2: Identification of Technically Infeasible Control Technology Options

Good combustion practices is technically feasible. As noted in Section 1.2.2.2, an oxidation catalyst is not technically feasible.

1.2.3.3 Step 3: Ranking of Technically Feasible Control Technology Options

The combination of good combustion practices is the top-ranked control option.

1.2.3.4 Step 4: Evaluation of Most Effective Controls

A search of the USEPA's RBLC and available permits for similar sources was conducted to identify approved BACT VOC limits for natural gas fired simple-cycle combustion turbines operating at LNG production facilities. The details of this review were presented in Appendix C, Table C-3 of the permit application. This review shows that all but two combustion turbines at land-based LNG production facilities utilized good combustion practices as the sole control to meet BACT with a range of limits in units of ppmvdc, lbs/MMBtu, and lb/hr. No combustion turbines located at an offshore LNG export facility were identified using oxidation catalysts.

Based on this search, use of good combustion practices is the most stringent level of VOC control for combustion turbines that is technically feasible. Therefore, good combustion practices is considered to represent the most stringent level of VOC control achieved in practice.

A review of emission limits in SIPs and federal regulations did not identify any VOC emission limits for simple cycle combustion turbines that are more stringent than limits achieved in practice by good combustion practices.

1.2.3.5 Step 5: Selection of BACT

The Project is proposing to use good combustion practices to meet BACT for VOC emissions from the combustion turbines consistent with the BACT controls for all but one LNG project. To our knowledge, an oxidation catalyst has never been applied to a combustion turbine on floating structures and therefore this technology has not been demonstrated in practice for this type of application. Furthermore, since the VOCs in the combustion turbine are not know, combustion turbine vendors will not lower guarantee a VOC emissions reduction for units with an oxidation catalyst and therefore potential VOC emissions will not be reduced with an oxidation catalyst.

As noted in Section 4.4.2.5, an oxidation catalyst will impose significant economic impacts, result in a significant increase in H_2SO_4 emissions, and provide little environmental benefit. For these reasons, oxidation catalysts were eliminated as a BACT option.

The selected BACT rate is provided below and is based upon the vendor guaranteed steady state emission rate.

- Siemens SGT-400: 1.4 ppmvdc

The above rate reflects BACT during steady state operation at or above 50 percent of rated operating load. These rates are reflected in the vendor performance data provided in Appendix D of the application. Compliance with the emission rate will be verified during initial performance testing. A review of other recently approved LNG projects including 2018 Driftwood LNG, 2020 Lake Charles LNG, and 2016 Golden Pass LNG did not indicate any continuous compliance methods beyond initial performance testing. NFE proposes to meet the same standard as similar projects for VOC compliance which is to complete initial performance testing.

Emissions during SU/SD will be limited through good operating practices to minimize the duration of SU/SD events to achieve the steady state BACT rate as quickly as possible.

1.2.4 PM/PM_{10}/$PM_{2.5}$

1.2.4.1 Step 1: Identification of Control Technology Options

Process Modifications

The process is the combustion turbines fired with natural gas which will have inherently low PM emission rates. Emissions of PM from combustion of natural gas can occur as a result of trace inert solids contained in the fuel and products of incomplete combustion, which may agglomerate or condense to form particles. All of the PM emitted from the combustion turbines is considered to be $PM_{2.5}$. Therefore, the PM, PM_{10} and $PM_{2.5}$ emission rates are assumed to be equivalent.

Add-on Controls

This evaluation did not identify any PM/PM_{10}/$PM_{2.5}$ post-combustion control technologies available for combustion turbines. Post-combustion PM control technologies such as fabric filters (baghouses), electrostatic precipitators, and/or wet scrubbers, which are commonly used on solid-fuel and heavy oil-fueled boilers, are not available for combustion turbines since the large amount of excess air inherent to combustion turbine technology would create an unacceptable amount of backpressure for combustion turbine operation. There are no known combustion turbine facilities that are equipped with a post-combustion PM control technology.

1.2.4.2 Step 2: Identification of Technically Infeasible Control Technology Options

The only known control option for PM/PM_{10}/$PM_{2.5}$ from combustion turbines is to use clean-burning fuels and ensure good combustion practices. The project will use natural gas as the sole fuel in the combustion turbines.

1.2.4.3 Step 3: Ranking of Technically Feasible Control Technology Options

The firing of natural gas as the sole fuel and good combustion practices is the top level of technically feasible controls.

1.2.4.4 Step 4: Evaluation of Most Effective Controls

The results of the search of the RBLC and other available permits for PM/PM_{10}/$PM_{2.5}$ BACT precedents were presented in Appendix C, Table C-4 of the permit application. Based on this search, use of clean-burning fuels and good combustion practices are the most stringent available technologies for control of combustion turbine PM_{10}/$PM_{2.5}$ emissions.

A review of Table C-4 indicates that PM/PM_{10}/$PM_{2.5}$ emission limits have been expressed either in lb/hr or lb/MMBtu units. A review of the permitted PM/PM_{10}/$PM_{2.5}$ emission limits for natural gas-fueled combustion turbines shows a wide-range of values. It is important to recognize that the differences in PM/PM_{10}/$PM_{2.5}$ emission limits among various projects are mostly due to different emission guarantee philosophies of the various combustion turbine vendors and are not believed to be actual differences in the quantity of PM/PM_{10}/$PM_{2.5}$ emissions produced by the various combustion turbine models. The different emission guarantee philosophies are influenced by the overall uncertainties of the PM/PM_{10}/$PM_{2.5}$ test procedures, especially given reported difficulties in achieving test repeatability, and concerns with artifact emissions introduced by the inclusion of condensable particulate emissions in permit limits in the last decade. All of the PM/PM_{10}/$PM_{2.5}$ emission limits listed in Table C-4 are based upon good combustion practices and vendor performance emissions guarantee.

The Project is proposing BACT PM/PM_{10}/$PM_{2.5}$ limits based upon the vendor emission guarantee provided for each combustion turbine proposed for the Project. The proposed limits are well within in the range of the other PM/PM_{10}/$PM_{2.5}$ BACT limits in Table C-4.

A review of emission limits in SIPs and federal regulations did not identify any $PM/PM_{10}/PM_{2.5}$ emission limits for simple cycle combustion turbines that are more stringent than limits achieved in practice by good combustion practices.

1.2.4.5 Step 5: Selection of BACT

The Project is proposing to use the most stringent level of control, firing natural gas as the sole fuel and good combustion practices for the combustion turbines and duct burners. The selected BACT rate for each turbine is provided below and is based upon the vendor guaranteed steady state emission rate at full operating load.

- Siemens SGT-400: 0.007 lb/MMBtu

The above rate reflects BACT during steady state operation at or above 50 percent of rated operating load. Emissions during SU/SD will be limited through good operating practices to minimize the duration of SU/SD events to achieve the steady state BACT rate as quickly as possible.

The proposed controls represent the top level of control that is technically feasible and have been demonstrated to be achievable in practice. Pursuant to EPA guidance, an evaluation of economic and energy impacts has not been conducted. There are no unacceptable collateral environmental impacts associated with the proposed $PM/PM_{10}/PM_{2.5}$ BACT.

1.2.5 SO_2 and H_2SO_4

Emissions of SO_2 and H_2SO_4 are formed from the oxidation of sulfur in the fuel and therefore the BACT for these two pollutants has been combined.

1.2.5.1 Step 1: Identification of Control Technology Options

Process Modifications

Emissions of SO_2 and H_2SO_4 are formed from the oxidation of sulfur in the fuel. Normally, all sulfur compounds contained in the fuel will oxidize, with the vast majority initially oxidizing in the combustion turbine to SO_2 and a smaller percentage to SO_3. After being formed, SO_3 reacts with water in the exhaust to form H_2SO_4 and sulfate particulate. There are no process modifications available to reduce SO_2 and H_2SO_4 emissions from the combustion turbine.

Add-on Controls

This evaluation did not identify any post-combustion control technologies available for SO_2 and H_2SO_4 emissions from combustion turbines. Post-combustion SO_2 and H_2SO_4 control technologies, such as dry or wet scrubbers that are commonly used on solid-fuel and heavy oil-fueled boilers, are not available for combustion turbines since the large amount of excess air inherent to combustion turbine technology would create an unacceptable amount of backpressure for combustion turbine operation. Furthermore, the low concentrations of SO_2 and H_2SO_4 in the exhaust gas, typically less than 1 ppmvdc, would make further reductions very difficult, if not impossible, to achieve. A review of readily available information did not identify any combustion turbines that are equipped with post-combustion SO_2 and H_2SO_4 control technologies.

1.2.5.2 Step 2: Identification of Technically Infeasible Control Technology Options

The only known control option for SO_2 and H_2SO_4 from a combustion turbine is to use low-sulfur fuels, such as natural gas, and ensure good combustion practices.

1.2.5.3 Step 3: Ranking of Technically Feasible Control Technology Options

The firing of natural gas and BOG as the sole fuels is the only technically feasible control.

1.2.5.4 Step 4: Evaluation of Most Effective Controls

The results of the search of the RBLC and other available permits for SO_2 and H_2SO_4 BACT precedents were presented in Appendix C, Table C-5 of the permit application. This search confirms that the only SO_2 and H_2SO_4 BACT technology identified for combustion turbines is use of low-sulfur fuel (e.g., natural gas). There were no cases identified of any post-combustion controls used to control SO_2 and H_2SO_4 emissions from combustion turbines.

1.2.5.5 Step 5: Selection of BACT

The Project is proposing to use the most stringent level of control, using natural gas as the sole fuel for the combustion turbines. The Project's design is based upon a maximum sulfur content of 20 ppmv which is equivalent to an emission rate of 0.003 lb/MMBtu. The proposed BACT emission rate for H_2SO_4 is 0.00023 lb/MMBtu which reflects a 5 percent conversion of SO_2 to H_2SO_4.

Use of natural gas and BOG as the sole fuels provides the greatest level of H_2SO_4 reduction technically feasible and represents the top level of control. Pursuant to EPA guidance, an evaluation of economic and energy impacts has not been conducted. There are no unacceptable collateral environmental impacts associated with the proposed H_2SO_4 BACT.

ATTACHMENT H

GHG BACT ANALYSIS

New Fortress Energy Louisiana FLNG Project

Prevention of Significant Deterioration and Title V Operating Permit Applications Greenhouse Gas Best Available Control Technology Analysis

Submitted to:

United States Environmental Protection Agency Region 6
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February 2023

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ACRONYMS/ABBREVIATIONS

Acronyms/Abbreviations	Definition
°C	degrees Celsius
°F	degrees Fahrenheit
AGDC	Alaska Gasline Development Corporation
AVO	Audio, Visual, and Olfactory (AVO) Detection and Repair
the Applicant	New Fortress Energy Louisiana FLNG LLC
BACT	Best Available Control Technology
BOG	boil off gas
CAA	Clean Air Act
CCS	carbon capture and sequestration
CFR	Code of Federal Regulations
CGI	combustible gas indicator
CH_4	methane
CHP	Combined heat and power
CO	carbon monoxide
CO_2	carbon dioxide
CO_{2e}	carbon dioxide equivalents
DWP	deepwater port
DWPA	Deepwater Port Act of 1974, as amended
GCU	gas combustion unit
GE	General Electric
GHG	greenhouse gas
GWP	global warming potential
H_2SO_4	sulfuric acid
HHV	higher heating value
hP	horsepower
hr	hour
LAC	Louisiana Administrative Code
Lake Charles	Lake Charles LNG Exporting Terminal
Lb/MMBtu	pounds per million Btu
LDAR	leak detection and repair program

Acronyms/Abbreviations	Definition
LDEQ	Louisiana Department of Environmental Quality
LNG	liquified natural gas
MARAD	Maritime Administration
MMBtu/hr	million British thermal units per hour
NETL	National Energy Technology Laboratory
NO_X	nitrogen oxides
NSPS	New Source Performance Standard
NSR	New Source Review
NSR Manual	New Source Review (NSR) Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting
PDS	Preliminary Determination Summary
PM	particulate matter
PM_{10}	particulate matter with a diameter equal to or less than 10 microns
$PM_{2.5}$	particulate matter with a diameter equal to or less than 2.5 microns
the Project	New Fortress Energy Louisiana FLNG Project
PSD	Prevention of Significant Deterioration
PTE	potential to emit
RBLC	USEPA's RACT/BACT/LAER Clearinghouse
SECARB-USA	Southeast Regional CO2 Utilization and Storage Acceleration Partnership
SIP	Louisiana's State Implementation Plan
SO_2	sulfur dioxide
TCEQ	Texas Commission on Environmental Quality
tpy	tons per year
U.S.C	United States Code
USCG	United States Coast Guard
USDOE	United States Department of Energy
USEPA	United States Environmental Protection Agency

1.0 INTRODUCTION

New Fortress Energy Louisiana FLNG LLC ("Applicant"), a limited liability company organized under the laws of Delaware, is proposing to construct, own, and operate the New Fortress Energy ("NFE") Louisiana FLNG Project ("Project"), a deepwater port ("DWP") export terminal approximately 12 nautical miles off the southeast coast of Grand Isle, Louisiana. The Project will provide a safe and reliable source of much needed natural gas supplies to global markets in the form of liquified natural gas ("LNG"). The Project is consistent with the Applicant's commitment to make clean, affordable energy available to markets around the world. The Applicant is filing an application for a license to construct, own, and operate the DWP export terminal pursuant to the Deepwater Port Act of 1974, as amended ("DWPA"), and in accordance with the U.S. Coast Guard's ("USCG") and the Maritime Administration's ("MARAD") implementing regulations.

The Project will involve the installation of two nominal 1.4 million metric tonnes per annum liquefaction systems (FLNG1 and FLNG2) installed in the West Delta Lease Block 38 in approximately 30 meters (98 feet) of water. Each system will contain three platforms consisting of natural gas processing, natural gas liquefaction, and utilities and accommodations. The United States Environmental Protection Agency ("USEPA") is authorized by the Clean Air Act ("CAA"; 42 United States Code ["U.S.C."] section [§] 7401 et seq., as amended in 1977 and 1990), to promulgate regulations governing air pollution in the United States, which are codified in Title 40 of the Code of Federal Regulations ["CFR"], Parts 50 through 99. Per 33 U.S.C. § 1518(b). The DWPA requires that the laws and regulations of the nearest adjacent coastal state apply to a DWP. Louisiana is the nearest adjacent coastal state to the Project. Accordingly, Louisiana's State Implementation Plan ("SIP") and implementing regulations under Louisiana Administrative Code ("LAC") 33.III will apply to the Project. LAC 33.III will govern the air permitting requirements as well as other applicable air pollutant emission standards for construction and operation of the Project. The DWPA stipulates that air permits required for a DWP project will be administered and issued by the EPA. Accordingly, the air permits for the Project will be issued by EPA Region 6.

The Project will include equipment regulated as stationary emission sources subject to the air permit to construct and operate requirements under LAC 33.III. The Project's primary air emission sources will include natural gas fired compressor turbines, natural gas fired power generating turbines, thermal oxidizers to control acid gas from the gas treatment system, and flares used largely to safely handle gas streams during upset conditions, such as the effluent from pressure relief valves, and plant startup. Minor emission sources will include emergency generator engines, small package boilers, fuel oil storage tanks, and fugitive emissions from the gas handling equipment.

Emissions from the proposed Project will primarily consist of products of combustion from the natural gas fired compressor turbines, natural gas fired power generating turbines, thermal oxidizers and flares with smaller quantities of air emissions emitted from the ancillary equipment. The Project is subject to Prevention of Significant Deterioration ("PSD") permitting under LAC 33:III § 509 for emissions of nitrogen oxides ("NO_X"), carbon monoxide ("CO"), volatile organic compounds ("VOC"), particulate matter less than or equal to 10 microns in diameter and less than or equal to 2.5 microns ("PM_{10}/$PM_{2.5}$"), sulfur dioxide ("SO_2"), sulfuric acid ("H_2SO_4"), and greenhouse gases ("GHG"). The Applicant submitted a PSD application to EPA Region 6 on November 18, 2022. This document provides a detailed GHG BACT analysis for the Project's emission sources in response to EPA's Incomplete Application Determination letter dated December 19, 2022.

2.0 FACILITY DESCRIPTION

2.1 FACILITY SUMMARY

The Project will involve the installation of two nominal 1.4 million metric tonnes per annum liquefaction systems, FLNG1 and FLNG2, each will contain three platforms consisting of natural gas processing, natural gas liquefaction, plus utilities and accommodations. GHG emissions from the proposed Project will primarily be emitted from the natural gas fired compressor turbines, natural gas fired power generating turbines, thermal oxidizers and flares with smaller quantities of GHG emissions emitted from the smaller ancillary equipment.

2.2 DESCRIPTION OF MAJOR GHG EMITTING EQUIPMENT

2.2.1 Compressor Combustion Turbines

Each FLNG will include a General Electric ("GE") LM6000PF natural gas-fired simple cycle refrigerator compressor turbine. Natural gas to be combusted in the compressor turbines will be comprised of boil off gas ("BOG") from the FSU's LNG storage tanks. The turbine will drive the compressor for the liquefaction refrigeration system. The turbine will have a maximum heat input rating of approximately 482 million British thermal units ("MMBtu") per hour (higher heating value, "HHV") at 15 degrees Celsius ("°C"; 59 degrees Fahrenheit ["°F"]) ambient temperature when firing the design case natural gas. The GE LM6000PF turbine may operate for up to 8,760 hours per year at full load. Potential annual GHG emissions were estimated based upon a heat input of 482 MMBtu/hr for 8,760 hours using the carbon dioxide ("CO_2"), methane ("CH_4"), and nitrous oxide ("N_2O") emission factors provided in 40 CFR § 98, Subpart C and the GWPs in 40 CFR § 98, Subpart A.

The estimated potential GHG emissions from the GE LM6000PF compressor turbines are 494,059 tons per year ("tpy") representing 37.1 percent of the Project's stationary source GHG emissions.

2.2.2 Power Generating Combustion Turbines

Each FLNG will include three Siemens SGT-400 natural gas–fired simple-cycle power generating turbines. Natural gas will be provided by the undersea pipeline. These turbines will generate electricity to power all the electric-driven equipment on each FLNG. Each turbine will have a maximum heat input rating of approximately 174 MMBtu/hour (HHV) at 15°C (59°F) ambient temperature. The turbines may operate for up to 8,760 hours per year at full load. Potential annual GHG emissions were estimated based upon a heat input of 174 MMBtu/hr for 8,760 hours using the carbon dioxide CO_2, CH_4, and N_2O emission factors provided in 40 CFR § 98, Subpart C and the GWPs in 40 CFR § 98, Subpart A.

The estimated potential GHG emissions from the three Siemens SGT-400 power generating turbines are 534,911 tpy representing 40.1 percent of the Project's stationary source GHG emissions.

2.2.3 Acid Gas Thermal Oxidizer

Each FLNG will include a natural gas–fired thermal oxidizer of John Zink design to control emissions of hydrogen sulfide ("H_2S") and residual hydrocarbons in the waste gas from the amine stripper column on the gas treatment platform. The feed gas pre-treatment system uses an amine solution to remove CO_2 and H_2S from the incoming pipeline gas. Steam is used to remove CO_2 and H_2S from the amine solution and the waste gas is sent to a thermal oxidizer. The oxidizer will be designed to handle a peak waste gas flow rate of approximately 20,000 pounds per hour of low heat content gas. The thermal oxidizer will have a supplemental natural gas heat input rate of approximately 12.2 MMBtu/hour during normal operation with low heat content waste gas. The oxidizer may operate at full load for up to 8,760 hours per year. CO_2 emissions were estimated based upon the carbon content of all carbon containing constituents in the waste gas and 99.9 percent conversion to CO_2. CH_4 emissions were estimated based upon the CH_4 content in the waste gas and 99.9 percent conversion to CO_2. N_2O emissions from supplemental natural gas firing were estimated based upon the natural gas consumption rate and emission factors provided in 40 CFR 98, Subpart C. GHG emissions were estimated the GWPs in 40 CFR § 98, Subpart A.

The estimated potential GHG emissions from the two thermal oxidizers are 184,732 tpy representing 13.9 percent of the Project's stationary source GHG emissions.

2.2.4 Wet and Dry Flares

Each FLNG will be equipped with one dry flare that will flare off gases vented from relief valves in the cryogenic portions of the liquefaction or LNG storage systems. The main purpose of the dry flare is to safely handle gas streams during upset conditions, such as the effluent from pressure relief valves and the blowdown system. The dry flare can also be used during periodic maintenance operations to de-inventory equipment and during startup of the cryogenic plant. The dry flare is designed for a maximum gas relief rate of 430,000 kilograms per event. The dry flare will be operated with a small amount of purge gas at all times to ensure readiness in the event of an emergency. Potential emissions from the dry flares are conservatively based on one startup event, one shutdown event, and one emergency event per year plus normal operation. Emissions of CO_2 and N_2O emissions were estimated using emission factors provided in 40 CFR 98, Subpart C. CH_4, emissions were estimated based upon 99 percent destruction of methane, ethane, and propane in the gas stream. GHG emissions were estimated the GWPs in 40 CFR § 98, Subpart A.

Each FLNG will be equipped with one wet flare, which will flare off any gases vented from relief valves and the blowdown system of the feed gas treatment platform. The main purpose of the wet flare is to safely handle gas streams during upset conditions, such as the effluent from pressure relief valves and the blowdown system. The wet flare can also be used during periodic maintenance operations to de-inventory equipment and during startup of the gas treatment platform. The wet flare is designed for a maximum gas relief rate of 300,000 kilograms per event. The wet flare will be operated with a small amount of purge gas at all times to ensure readiness in the event of an emergency. Potential emissions from the wet flares are conservatively based on one startup event, one shutdown event, and one emergency event per year plus normal operation.. Emissions of CO_2 and N_2O emissions were estimated using emission factors provided in 40 CFR 98, Subpart C. CH_4, emissions were estimated based upon 99.9 percent destruction of methane, ethane, and propane in the gas stream. GHG emissions were estimated the GWPs in 40 CFR § 98, Subpart A.

The estimated potential GHG emissions from the four flares are 106,581 tpy representing 8.0 percent of the Project's stationary source GHG emissions.

2.3 ANCILLARY EQUIPMENT

The estimated potential GHG emissions from all ancillary sources, including fugitive emissions, is only 12,118 tpy, representing less than one percent of the Project's stationary source GHG emissions.

2.3.1 Emergency Generator Engines

Each FLNG will include 7 diesel-fired emergency generator engines. FLNG1 will be equipped with six Caterpillar 3516 and one Caterpillar 3512 or similar model engines. The Caterpillar 3516 engines will have a standby power generation rate of approximately 1,750 kW of shaft power output, with a maximum heat input rate of approximately 17.1 MMBtu/hour. The Caterpillar 3512 engines will have a standby power generation rate of approximately 1,100 kW of shaft power output, with a maximum heat input rate of approximately 11.1 MMBtu/hour. FLNG2 will be equipped with five Caterpillar 3512C and two Caterpillar C18 or similar model engines. The Caterpillar 3512C engines will have a standby power generation rate of approximately 1,821 kW of shaft power output, with a maximum heat input rate of approximately 16.2 MMBtu/hour. The Caterpillar C18 engines will have a standby power generation rate of approximately 600 kW of shaft power output, with a maximum heat input rate of approximately 5.5 MMBtu/hour. The FSU will be equipped with one Cummins Model KTA38 engine with a standby power generation rate of approximately 850 kW of shaft power output, with a maximum heat input rate of approximately 7.8 MMBtu/hour.

The emergency generator engines will operate to generate electricity during emergencies and for maintenance and testing. The engines will meet the criteria of emergency generator engines and will be subject to the applicable standards under 40 CFR 60 Subpart IIII, which for an engine of this size and purpose, are the EPA Tier 2 standards for engines larger than 560 kW, as listed in 40 CFR § 89.112. Annual potential emissions assume that each generator engine will operate at its rated heat input for up to 100 hours per year at full load consistent with the allowable non-emergency operation specified under 40 CFR § 60.4211(f)(2). GHG emissions were estimated using the CO_2, CH_4, and N_2O emission factors provided in 40 CFR § 98, Subpart C and the GWPs in 40 CFR § 98, Subpart A.

2.3.2 Emergency Fire Pump Engines

FLNG2 will include 8 diesel-fired emergency fire pump engines; FLNG1 will be equipped with electric powered fire pumps. FLNG2 will be equipped with six Clarke C32 and two Clarke C18 or similar model engines. The Clarke C32 engines will have a rated engine power of 1,047 horsepower ("hP") with a maximum heat input rate of approximately 7.1 MMBtu/hour. The Clarke C18 engines will have a rated engine power of 460 hP with a maximum heat input rate of approximately 3.1 MMBtu/hour.

The emergency fire pump engines will operate in the event of a fire and for maintenance and testing. The engines will meet the criteria of emergency generator engines and will be subject to the applicable standards under 40 CFR 60 Subpart IIII. The engines will meet the stipulated emission standards for fire pump engines under 40 CFR 60 § Subpart IIII. Annual potential emissions assume that each engine will operate at its rated heat input for up to 100 hours per year at full load consistent with the allowable non-emergency operation specified under 40 CFR § 60.4211(f)(2). GHG emissions were estimated using the CO_2, CH_4, and N_2O emission factors provided in 40 CFR § 98, Subpart C and the GWPs in 40 CFR § 98, Subpart A.

2.3.3 Gas Combustion Unit

The FSU will be equipped with a gas combustion unit ("GCU") to combust boil-off gas ("BOG") released during gas freeing and purging procedures. The maximum BOG firing rate of the GCU was estimated to be equal to 0.15% of FSU LNG storage capacity based upon its design specifications. It was estimated that the GCU will operate up to 12 hours per month and 144 hours per year. GHG emissions were estimated using the CO_2, CH_4, and N_2O emission factors provided in 40 CFR § 98, Subpart C and the GWPs in 40 CFR § 98, Subpart A.

2.3.4 Package Boilers

The FSU will be equipped with two distillate oil fired package boilers with a steam generating capacity of 5,000 kilograms per hour. Each boiler will have a maximum heat input rate of approximately 5.35 MMBtu/hour. The boilers will operate in parallel to supply steam for cargo operations which includes gas heaters, glycol water heater, and general heating services. Potential emissions for the boilers were estimated based upon full load operation for up to 8,760 hours per year. GHG emissions were estimated using the CO_2, CH_4, and N_2O emission factors provided in 40 CFR § 98, Subpart C and the GWPs in 40 CFR § 98, Subpart A.

2.3.5 Natural Gas and LNG Handling Systems

Each FLNG will have various fugitive emission points, related to LNG vapor leakage from valves, flanges, pressure relief valves, and other components in the LNG piping system. Potential emissions are based on estimated component totals for each FLNG, and fugitive emission factors for oil and gas production operations contained in EPA's November 1995 *Protocol for Equipment Leak Emission Estimates* (EPA 1995).

2.4 POTENTIAL GHG EMISSIONS

GHG emissions from the Facility will consist primarily of CO_2 from the combustion of fuel with minor amounts of CH_4 and N_2O. Over 99 percent of the Facility's total GHG emissions are CO_2 emissions. Table 2-1 presents a summary of the potential GHG emissions from the facility. Potential GHG emission calculations were provided in Appendix B of the PSD application.

Table 2-1: Potential Annual GHG Emissions (tons per year (tpy))

Source	CO_2	CH_4	N_2O	GHGs as CO_2e	% of Project Total
(2) GE LM6000PF Turbines	493,548	9.3	0.9	494,059	37.1
(3) Siemens SGT-400 Turbines	534,358	10.1	1.0	534,911	40.1
(2) Thermal Oxidizers	184,585	5.5	0.03	184,732	13.9
(2) Dry Flares	57,562	202.5	0.1	62,656	4.7
(2) Wet Flares	40,359	141.7	0.1	43,925	3.3
(14) Emergency Generator Engines	1,676	0.06	0.01	1,682	0.13
(8) Emergency Fire Pump Engines	311	0.02	0.003	312	0.02
(2) FSU Package Boilers	7,641	0.3	0.06	7,667	0.6
FSU Emergency Engine	63	0.003	0.0005	64	0.005
FSU GCU	1,661	0.5	0.003	1,797	0.13
Fugitive Emissions	0.012	23.8	0	596	0.04
Project Totals	1,321,765	379.6	2.5	1,332,401	100

CO_2e = carbon dioxide equivalent

3.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

3.1 DEFINITION OF BACT

In accordance with LAC 33:III § 509(B), BACT is as follows:

> *"an emissions limitation, including a visible emission standard, based on the maximum degree of reduction for each pollutant subject to regulation under this Section that would be emitted from any proposed major stationary source or major modification that the administrative authority, on a case by case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant."*

From the above definition, the following factors must be considered when determining if an emission limitation is achievable:

- A previous BACT approval for a similar or a representative type of source;
- Technological limitations; and
- Energy, economic and environmental impacts.

3.2 BACT PROCESS

The BACT process is described in USEPA's draft "New Source Review ("NSR") Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting" ("NSR Manual") (USEPA 1990). The USEPA describes a five-step "top-down" process to identify BACT involving the following steps:

1. identify all control technologies;
2. eliminate technically infeasible options;
3. rank remaining control technologies by control effectiveness;
4. evaluate most effective controls and documents results; and
5. select BACT.

Following is a description of the steps followed for each BACT-subject pollutant for each emission source.

3.2.1 Step 1: Identification of Control Technology Options

The first step in the BACT analysis is the identification of available control technologies, including an evaluation of transferable and innovative control measures that may not have been previously applied to the source type under analysis. For emission sources with a large number of recent control technology determinations, available control technologies can be identified from the various agency reviews of these similar projects. A review was conducted of recent technical determinations made by USEPA and various state air agencies to identify available control technology options for each proposed emission source and each subject pollutant.

3.2.2 Step 2: Identification of Technically Infeasible Control Technology Options

Once all control technology options are identified, each is evaluated to determine if it is technically feasible for the proposed emission source. This determination is made on a case-by-case basis in accordance with regulatory guidance. A control option may be shown to be technically infeasible by documenting that technical difficulties would preclude the successful use of the control option on the emissions unit under review. Per regulatory guidance, a permit requiring the application of a technology is sufficient justification to assume the technical feasibility of that technology unless the permitted source and control equipment could not demonstrate compliance with the permitted limit(s). Once a technology is shown to be technically infeasible, it is eliminated as a BACT control technology, and no further review is required.

3.2.3 Step 3: Ranking of Technically Feasible Control Technology Options

After technically infeasible control technologies have been eliminated, the remaining control options are ranked by control effectiveness. The minimum requirement for a BACT proposal is an option that meets federal New Source Performance Standard ("NSPS") limits or other minimum state or local requirements, such as IEPA emission standards.

3.2.4 Step 4: Evaluation of Most Effective Controls

The USEPA's draft NSR Manual states that:

> *"if the applicant accepts the top alternative in the listing as BACT, the applicant proceeds to consider whether impacts of unregulated air pollutants or impacts in other media would justify selection of an alternative control option. If there are no outstanding issues regarding collateral environmental impacts, the analysis is ended and the results proposed as BACT. In the event that the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding should be documented for the public record. Then the next most stringent alternative in the listing becomes the new control candidate and is similarly evaluated. This process continues until the technology under consideration cannot be eliminated by any source-specific environmental, energy, or economic impacts which demonstrate that alternative to be inappropriate as BACT."*

In USEPA's guidance document "PSD and Title V Permitting Guidance for Greenhouse Gases" (USEPA 2011), it states that "the top-ranked option should be established as BACT unless the permit applicant demonstrates to the satisfaction of the permitting authority that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the top-ranked technology is not 'achievable' in that case." Accordingly, an evaluation of energy, environmental, or economic impacts is applied only when an applicant wants to demonstrate that the top-ranked technically feasible option results in unacceptable energy, environmental, and/or economic impacts.

Per USEPA guidance, BACT is expressed as an emission rate and the top level of control is determined from the following:

- The most stringent emissions limitation which is contained in any State Implementation Plan (SIP) for such class or category of stationary source; or
- The most stringent emissions limitation which is achieved in practice by such class or category of stationary source.

To identify the "most stringent emissions limitation which is achieved in practice", numerous sources of information were evaluated, including the following:

- USEPA's RACT/BACT/LAER Clearinghouse ("RBLC");
- The California Air Resources Board BACT Clearinghouse;
- USEPA regional air permitting websites; and
- State environmental agency websites.

Step 4 validates the feasibility of the top control option as BACT or provides justification why the top control option is not appropriate as BACT due to adverse economic, energy, and/or environmental impacts. For the Facility, if there was only a single technically feasible option, or if the top-ranked control option was proposed, then no further analysis was conducted other than a check of potentially unacceptable collateral environmental impacts. If two or more technically feasible options were identified, and the most stringent (top) level of control was not proposed, the next three steps (as presented below) were applied to demonstrate that the economic, energy, and/or environmental impacts of the top-ranked option imposed an adverse impact on the Facility. In these instances, the rationale for not selecting the top candidate as BACT was documented and the criteria for adverse impacts defined. Then, the next most effective control option became the control candidate and was similarly evaluated. This process continued until the control technology under consideration could not be eliminated by environmental, energy, and/or economic impacts which demonstrate that the alternative is not appropriate as BACT.

3.2.4.1 Economic Impacts

The economic analysis consists of evaluating the cost-effectiveness of a technically feasible control technology. Cost effectiveness for non-GHG pollutant emissions has historically been evaluated on a dollar per ton of emissions removed basis whereas the USEPA has made a number of adverse economic impact decisions for GHG controls due to excessive costs. For dollars per ton of emissions removed analyses, the annual emissions with a control option are subtracted from base-case emissions to calculate tons of pollutant controlled. The base case may be uncontrolled emissions, or the maximum emission rate allowed by regulation (such as an NSPS limit). Annual costs are calculated by the sum of operation and maintenance costs, plus the annualized capital cost of the control option. Operating and maintenance costs may take into account a reduction in the output capacity or reliability of a unit. The cost-effectiveness on a dollars per ton of pollutant removed for a control option is the annual cost (dollars per year) divided by the annual reduction in pollutant emissions (tpy). For GHG cost to control analyses based on capital costs, the criteria applied is the percent increase in total project capital costs due to the control option. If the calculated cost is deemed too high, then a control option may be eliminated as BACT. If the most effective control option is proposed, or if there are no technically feasible control options, an economic analysis is not required.

3.2.4.2 Energy Impacts

The consumption of energy by the control option itself is a quantifiable energy impact. These impacts can be quantified by either an increase in fuel consumption, reduced product output per unit of energy consumed, or fuel consumption to power the control equipment.

3.2.4.3 Environmental Impacts

The environmental impact analysis concentrates on other impacts such as solid or hazardous waste generation, waste discharges from a control device, visibility impacts, or emissions of additional pollutants. Collateral increases or decreases in air pollutant emissions of other criteria or non-criteria pollutants may occur with a control option and should be evaluated. These additional impacts are identified and qualitatively and/or quantitatively evaluated as appropriate.

3.2.5 Step 5: Selection of BACT

The most effective control option not eliminated in Step 4 is selected as BACT.

3.3 COMPRESSOR COMBUSTION TURBINES

USEPA issued a 2011 guidance document for completing GHG BACT analyses titled "*PSD and Title V Permitting Guidance for Greenhouse Gases*" (USEPA 2011). This guidance is in addition to the NSR Manual (USEPA 1990), which provides detailed BACT guidance. Although the 2011 guidance document refers to the same top-down methodology described in the NSR Manual, the 2011 guidance provides additional clarification and detail with regard to some aspects of the analysis for GHG emissions. The following analysis has been conducted in accordance with both the 1990 and 2011 guidance documents.

3.3.1 Step 1: Identify GHG Control Options

Emission reductions can be achieved through the following three measures:

- A change in raw materials where substitution to a lower emitting raw material may be technically feasible.
- Process modifications where a change in the process may result in lower emissions.
- Add-on control equipment to capture and reduce emissions.

3.3.1.1 Raw Materials

For the Project, the "raw material" would be the fuel combusted in the combustion turbines. Fuels that can be combusted in the turbines are diesel oil, natural gas, renewable natural gas, and hydrogen. Diesel oil has the highest carbon content of the available fuels and therefore was eliminated as a BACT option. Renewable natural gas is essentially biogas that has been processed to purity standards. Renewable natural gas generally comes from landfills, animal farms, and wastewater treatment. There is no supply of renewable natural gas available for the Project and therefore this was eliminated as a BACT option. Combustion turbine vendors are currently researching the combustion of hydrogen in turbines. GE has successfully fired hydrogen up to 5 percent by volume in their combustion turbines over short periods of time. Firing hydrogen at 5 percent by volume represents a reduction in carbon emissions of less than 1 percent as the molecular weight of hydrogen is only 12 percent of the molecular weight of natural gas. The Applicant is not aware of any commercial combustion turbine firing hydrogen in continuous operation. Hydrogen would also require storage on the platform and deliveries at sea which would be technically challenging. As firing of hydrogen for a commercial compressor turbine in continuous service has never been demonstrated in practice, would achieve an insignificant reduction in GHG emissions as a blend with natural gas for intermittent operation, and would be difficult to obtain at sea, hydrogen was eliminated as a lower emitting fuel for the Project.

Therefore, the lowest emitting fuel for the compressor turbines is natural gas.

3.3.1.2 Process Modifications

Process modifications considered for the combustion turbines include the following:

- electric compression;
- waste heat recovery;
- combustion intake air cooling; and
- design and operational efficiency measures.

Electric compression involves the use of an electric motor to drive the compressor. The only source of electricity for the Project is from the Siemens SGT-400 combustion turbines. The GE LM6000PF combustion turbine has a higher efficiency than the Siemens SGT-400 combustion turbines. Therefore, using electric compression driven by electricity generated by the Siemens SGT-400 combustion turbines would increase GHG emissions and therefore, electric compression was eliminated as a BACT option.

Waste heat recovery involves installation of a heat recovery system in the combustion turbine exhaust to use the recovered heat for another purpose. This technology is commonly used for power generation to generate steam used to power a steam turbine generator. It is also used for combined heat and power plants to use the steam for heating and cooling purposes. The Project employs waste heat recovery on the Siemens SGT-400 combustion turbines to provide heat to the hot oil system. The hot oil system is used for utility heating of the various energy consuming equipment on the FLNGs including amine regeneration, dehydration regeneration, heavy hydrocarbon vaporization, and feed gas heating. There are no additional uses for waste heat recovered from the compressor turbines and therefore, it was eliminated as a BACT option.

Combustion air intake cooling involves cooling the turbine inlet air to increase its density and increase turbine output. A turbine operating in hot weather requires the inlet system and compressor to expend more energy on air intake to reach the amount of air needed for combustion. There are two primary types of inlet air cooling systems, evaporative cooling and mechanical chilling. Evaporative cooling involves spraying fresh water into the inlet air to cool it through evaporation. Evaporative cooling requires fresh water which will not be available at the DWP and therefore was eliminated as a BACT option. Mechanical chilling requires electricity and operates in a similar manner to air conditioning. As mechanical chilling will require electricity, increased operation of the Siemens SGT-400 power generating turbines would be required. The average ambient temperature at the platforms will be 70 degrees Fahrenheit ("°F"). Mechanical chillers could cool the inlet air to 45-50°F. Vendor data for the GE LM6000PF shows an increase in efficiency from 91.4°F to 53.6°F of 5 percent, extrapolating this starting from 70°F and chilled inlet air to 50°F indicates an approximate 2.5 percent increase in efficiency could be achieved with mechanical chilling.

The compressor turbines implement advanced combustion turbine design to achieve the highest efficiency available. The turbines achieve nearly complete combustion of the natural gas as evidenced by the low carbon monoxide ("CO") emission rates. Full oxidation is desirable because CO is a product of incomplete combustion and a regulated criteria pollutant. Complete combustion also results in more useful energy and thereby ensures high efficiency operation. The Project's design has made every attempt to use the most efficient equipment available to limit energy demand to ensure efficient energy operation. By utilizing more efficient technology, less fuel is required to produce the same amount of output.

The Applicant will operate and maintain all Project equipment in accordance with manufacture specifications and recommendations to ensure that it operates near design efficiency through the life of the Project.

3.3.1.3 Add-on Controls

Carbon Capture and Sequestration ("CCS")

There are limited post-combustion options for controlling CO_2. The USEPA indicated in *PSD and Title V Permitting Guidance for Greenhouse Gases* (USEPA 2011) that carbon capture and sequestration (CCS) should be considered in Step 1 of a top-down BACT analysis and evaluated in Step 2 of the process. USEPA did state that technical feasibility should be evaluated on a case-by-case basis. This control option is discussed in greater detail below per USEPA guidance.

CCS is a developing technology that requires three distinct processes:

- removal of CO_2 from the exhaust gas;
- transportation of the captured CO_2 to a suitable storage location; and,
- safe and secure storage of the captured and delivered CO_2.

The first step in the CCS process is capture of the CO_2 from the turbine exhaust in a form that is suitable for transport. There are several methods that may be used for capturing CO_2 from gas streams, including chemical and physical absorption, cryogenic separation, and membrane separation. Exhaust streams from combustion turbines have relatively low CO_2 concentrations, typically around five percent, compared to 12 to 15 percent in the exhaust from a coal-fired boiler. Only physical and chemical absorption would be considered technically feasible for a high-volume, low-concentration gas stream such as the exhaust from the combustion turbines.

The next step in the CCS process is transportation of the captured CO_2 to a suitable storage location. Captured CO_2 can be used for enhanced oil recovery or sequestered in deep saline formations and unrecoverable coal seams Currently, development of commercially available CO_2 storage sites is in its infancy and there are no commercially operating sites available for the storage of CO_2 from the Project. Louisiana is an area where the suitability of geological formations for CO_2 storage is being studied by the Southeast Regional CO_2 Utilization and Storage Acceleration Partnership ("SECARB-USA") project, which is funded by the United States Department of Energy ("USDOE"). There are several proposed projects in Louisiana to sequester CO_2 but there are no known sequestration facilities capable of handling the Project's CO_2 emissions currently in operation within the vicinity of the Project.

Currently, there are no known combustion turbine projects utilizing CCS and, although deemed theoretically feasible by the USEPA, this technology is not available with commercial guarantees for a combustion turbine facility.

3.3.2 Step 2: Technical Feasibility of Potential GHG Control Options

3.3.2.1 Low Carbon-Emitting Fuels

As discussed in Step 1, the lowest emitting fuel that is technically feasible for the compressor turbines is natural gas, which has been selected for the Project.

3.3.2.2 Process Modifications

Electric compression involves the use of an electric motor to drive the compressor. The only source of electricity for the Project is from the Siemens SGT-400 combustion turbines. The GE LM6000PF combustion turbine has a higher efficiency than the Siemens SGT-400 combustion turbines. Therefore, using electric compression driven by electricity generated by the Siemens SGT-400 combustion turbines would increase GHG emissions. For the Lake Charles LNG Exporting Terminal ("Lake Charles") PSD permit issued on September 9, 2020, which is a land based project with electricity readily available, the Louisiana Department of Environmental Quality's ("LDEQ") Preliminary Determination Summary ("PDS") concluded that electric-driven compressors would redefine the source and the use of electric-driven compressors was technically infeasible. For these reasons, electric compression was eliminated as a BACT option as technically infeasible.

Waste heat recovery involves installation of a heat recovery system in the combustion turbine exhaust to use the recovered heat for another purpose. This technology is commonly used for power generation to generate steam used to power a steam turbine generator. It is also used for combined heat and power plants to use the steam for heating and cooling purposes. The Project employs waste heat recovery on the Siemens SGT-400 combustion turbines to provide heat to the hot oil system. The hot oil system is used for utility heating of the various energy consuming equipment on the FLNGs including amine regeneration, dehydration regeneration, heavy hydrocarbon vaporization, and feed gas heating. There are no additional uses for waste heat recovered from the compressor turbines. Therefore, was heat recovery was eliminated as a BACT option as technically infeasible.

Combustion air intake cooling involves cooling the turbine inlet air to increase its density and increase turbine output. A turbine operating in hot weather requires the inlet system and compressor to expend more energy on air intake to reach the amount of air needed for combustion. There are two primary types of inlet air cooling systems, evaporative cooling and mechanical chilling. Evaporative cooling involves spraying fresh water into the inlet air to cool it through evaporation. Evaporative cooling requires fresh water which will not be available at the DWP and therefore was eliminated as a BACT option as technically infeasible. Mechanical chilling requires electricity and operates in a similar manner to air conditioning. Mechanical chillers are technically feasible and could increase the combustion turbine's efficiency by approximately 2.5 percent. The Project evaluated the use of chillers on the combustion turbines but determined that these large heavy pieces of equipment could not be accommodated with the weight restrictions on the offshore platforms and therefore eliminated as technically infeasible.

3.3.2.3 Energy Efficiency

USEPA's 2011 GHG permitting guidance states:

> "*Evaluation of [energy efficiency options] need not include an assessment of each and every conceivable improvement that could marginally improve the energy efficiency of [a] new facility as a whole (e.g., installing more efficient light bulbs in the facility's cafeteria), since the burden of this level of review would likely outweigh any gain in emissions reductions achieved. USEPA instead recommends that the BACT analyses for units at a*

new facility concentrate on the energy efficiency of equipment that uses the largest amounts of energy, since energy efficient options for such units and equipment (e.g., induced draft fans, electric water pumps) will have a larger impact on reducing the facility's emissions..."

USEPA also recommends that permit applicants:

"propose options that are defined as an overall category or suite of techniques to yield levels of energy utilization that could then be evaluated and judged by the permitting authority and the public against established benchmarks...which represent a high level of performance within an industry."

With regard to natural gas compression, the combustion turbine is considered to be the most efficient technology available.

The Lake Charles PDS identified an economizer to recover heat from the turbine exhaust gas to preheat boiler feedwater as a technically feasible design measure. The Project does not have boiler feedwater and therefore this is not a technically feasible option.

The Project's proposed use of advanced combustion turbine technology is the most efficient process technically available to minimize GHG emissions.

3.3.2.4 Carbon Capture and Storage

In USEPA's 2011 GHG BACT guidance, they stated that CCS should generally be considered technically achievable and considered in a GHG PSD BACT analysis for combustion turbines. However, USEPA noted in the 2011 guidance that the guidance was being issued at a time when add-on control technologies for GHGs or emissions sources may be limited in number and in various stages of development and commercialization and that CCS technologies may be more widely applicable in the future. The USEPA noted that "these facts are important to BACT Step 2, wherein technically infeasible control options are eliminated from further consideration." USEPA's GHG BACT guidance document states "to establish that an option is technically infeasible, the permitting record should show that an available control option has neither been demonstrated in practice nor is available and applicable to the source type under review." More than 11 years later, there are currently no known simple cycle combustion turbine projects equipped with CCS or currently proposed to install CCS. CCS has not been demonstrated in practice for a simple cycle combustion turbine.

USEPA 2011 GHG BACT guidance states that "logistical hurdles for CCS may include obtaining contracts for offsite land acquisition (including the availability of land), the need for funding (including, for example, government subsidies), timing of available transportation infrastructure, and developing a site for secure long-term storage." Installing CCS at a DWP includes all of these logistical hurdles, there is space available for a carbon capture system, securing funding for a project type that has never been demonstrated is not feasible, and there are no sites currently available for long term storage of the Project's CO_2.

For the Lake Charles project, LDEQ determined that CCS was technically infeasible due to the numerous technical and legal barriers hindering the widespread, cost-effective deployment of this technology.

The most recent PSD GHG BACT determination (July 29, 2022) for a combustion turbine project identified in the RBLC is for the Lincoln Land Energy Center in Illinois. The Illinois Environmental Protection Agency reviewed carbon capture technologies that have been studied to date by the United States Department of Energy's ("USDOE") National Energy Technology Laboratory ("NETL") including Monoethanolamine Scrubbing, Chilled Ammonia, Ammonia Scrubbing, and Gas Separation Membrane Technology and concluded that these technologies have not been demonstrated on combustion turbines and therefore carbon capture is not technically feasible for combustion turbines.

The most recent determination in the RBLC for a LNG liquefaction facility was for the Alaska Gasline Development Corporation ("AGDC") with a permit issued on July 7, 2022. The Alaska Department of Environmental Conservation determined that CCS was not technically feasible for any of the project's GHG emission sources.

Per USEPA guidance, the permitting record shows that CCS has never been demonstrated in practice for a large combustion turbine and is not available for a combustion turbine. There are no known combustion turbine projects that have proposed CCS and the most recent PSD GHG BACT determination confirms that carbon capture is not technically feasible for a combustion turbine. Consistent with USEPA's BACT guidance, CCS has been determined to be technically infeasible for the Project's simple cycle combustion turbines and therefore eliminated as a BACT option.

3.3.3 Step 3: Ranking of Technically Feasible GHG Control Options by Effectiveness

The technically feasible options are as follows:

- low emitting fuels;
- efficient design; and,
- combustion and efficiency measures.

The combination of all technically feasible control measures is the top-ranked control option.

3.3.4 Step 4: Evaluation of Most Effective Controls

All technically feasible control measures is the top-ranked control option and proposed as BACT for the Project. Therefore, an evaluation of the economic, environmental, and energy impacts of these options are not needed.

3.3.5 Step 5: Selection of BACT

The Project proposes the following control measures a GHG BACT for the compressor combustion turbines:

- firing natural gas, which is the lowest emitting fuel available for the combustion turbines;
- efficient Project design to minimize energy consumption; and
- use advanced combustion turbine technology which is the most efficient technology for natural gas compression.

A review of enforceable GHG emission limits for compressor turbines shows predominantly annual ton per year ("tpy") limits have been permitted. The Project proposes to limit annual GHG emissions from each combustion turbine as follows:

- GE LM 6000PF: 247,029 tpy per turbine

The AGDC permit included a short term GHG emission limit, as carbon dioxide equivalents ("CO_2e"), of 117.1 pounds per million Btu ("lb/MMBtu") for simple cycle combustion turbines. The Project will be required to report GHG emission in accordance with 40 CFR 98, Subpart C which is based upon the emission factors provided in Tables 1 and 2 of this subpart and the global warming potentials ("GWPs") provided in 40 CFR 98, Subpart A. The current emission factors and GWPs are equal to an emission rate of 117.0 lb/MMBtu. However, the GWPs and emission factors in 40 CFR 98 are subject to change and may increase or lower in the future. The Project proposes to comply with the applicable GWPs and emission factors in 40 CFR 98, Subparts A and C in effect for each reporting year.

A review of PSD GHG BACT precedents for combustion turbine projects was conducted to identify operating practices, efficiency measures, and compliance monitoring. The most applicable precents identified were for the Lake Charles and AGDC projects and includes:

- Operation in accordance with vendor recommendations including periodic tune-ups and maintenance for optimal thermal efficiency.
- Advanced combustion controls to maintain optimum excess air.
- Good combustion practices, meaning complete combustion of the natural gas as demonstrated through compliance with the CO BACT limit.

3.4 POWER GENERATING COMBUSTION TURBINES

USEPA issued a 2011 guidance document for completing GHG BACT analyses titled "*PSD and Title V Permitting Guidance for Greenhouse Gases*" (USEPA 2011). This guidance is in addition to the USEPA NSR Manual (USEPA 1990), which provides detailed BACT guidance. Although the 2011 guidance document refers to the same top-down methodology described in the 1990 Draft NSR Workshop Manual, the 2011 guidance provides additional clarification and detail with regard to some aspects of the analysis for GHG emissions. The following analysis has been conducted in accordance with both the 1990 and 2011 guidance documents.

3.4.1 Step 1: Identify GHG Control Options

Emission reductions can be achieved through the following three measures:

- A change in raw materials where substitution to a lower emitting raw material may be technically feasible.
- Process modifications where a change in the process may result in lower emissions.
- Add-on control equipment to capture and reduce emissions.

3.4.1.1 Raw Materials

For the Project, the "raw material" would be the fuel combusted in the combustion turbines. Fuels that can be combusted in the turbines are diesel oil, natural gas, renewable natural gas, and hydrogen. Diesel oil has the highest carbon content of the available fuels and therefore was eliminated as a BACT option. Renewable natural gas is essentially biogas that has been processed to purity standards. Renewable natural gas generally comes from landfills, animal farms, and wastewater treatment. There is no supply of renewable natural gas available for the Project and therefore this was eliminated as a BACT option. Combustion turbine vendors are currently researching the combustion of hydrogen in turbines. Siemens is currently running demonstration projects to fire hydrogen and natural gas blends in the SGT-400 turbine but this technology is not currently commercially available. Hydrogen would also require storage on the platform and deliveries at sea which would be technically challenging. As firing of hydrogen for a commercial combustion turbine in continuous service has never been demonstrated in practice, would achieve an insignificant reduction in GHG emissions as a blend with natural gas for intermittent operation, and would be difficult to obtain at sea, hydrogen was eliminated as a lower emitting fuel for the Project.

Therefore, the lowest emitting fuel for the power generating turbines is natural gas.

3.4.1.2 Process Modifications

Process modifications considered for the combustion turbines include the following:

- waste heat recovery;
- combustion intake air cooling; and
- design and operational efficiency measures.

Waste heat recovery involves installation of a heat recovery system in the combustion turbine exhaust to use the recovered heat for another purpose. This technology is commonly used for power generation to generate steam used to power a steam turbine generator. It is also used for combined heat and power plants to use the steam for heating and cooling purposes. The Project employs waste heat recovery on the Siemens SGT-400 combustion turbines to provide heat to the hot oil system. The hot oil system is used for utility heating of the various energy consuming equipment on the FLNGs including amine regeneration, dehydration regeneration, heavy hydrocarbon vaporization, and feed gas heating. There are no additional uses for waste heat recovered from the power generating turbines.

Combustion air intake cooling involves cooling the turbine inlet air to increase its density and increase turbine output. A turbine operating in hot weather requires the inlet system and compressor to expend more energy on air intake to reach the amount of air needed for combustion. There are two primary types of inlet air cooling systems, evaporative cooling and mechanical chilling. Evaporative cooling involves spraying fresh water into the inlet air to cool it through evaporation. Evaporative cooling requires fresh water which will not be available at the DWP and therefore was eliminated as a BACT option. Mechanical chilling requires electricity and operates in a similar manner to air conditioning. As mechanical chilling will require electricity, increased operation of the Siemens SGT-400 power generating turbines would be required. The average ambient temperature at the platforms will be 70°F. Mechanical chillers could cool the inlet air to 45-50°F. Vendor data for the Siemens SGT-400 shows an increase in efficiency from 102.2°F to 59°F of 5 percent, extrapolating this starting from 70°F and chilled inlet air to 50°F indicates an approximate 2.5 percent increase in efficiency could be achieved with mechanical chilling.

The power generating turbines implement advanced combustion turbine design to achieve the highest efficiency available. The turbines achieve nearly complete combustion of the natural gas as evidenced by the low CO emission rate. Full oxidation is desirable because CO is a product of incomplete combustion and a regulated criteria pollutant. Complete combustion also results in more useful energy and thereby ensures high efficiency operation. By utilizing more efficient technology, less fuel is required to produce the same amount of output. The Project's design has made every attempt to use the most efficient equipment available to limit energy demand to ensure efficient energy operation. By utilizing more efficient technology, less fuel is required to produce the same amount of output.

The Applicant will operate and maintain all Project equipment in accordance with manufacture specifications and recommendations to ensure that it operates near design efficiency through the life of the Project.

3.4.1.3 Add-on Controls

<u>CCS</u>

There are limited post-combustion options for controlling CO_2. The USEPA indicated in *PSD and Title V Permitting Guidance for Greenhouse Gases* (USEPA 2011) that carbon capture and sequestration (CCS) should be considered in Step 1 of a top-down BACT analysis and evaluated in Step 2 of the process. USEPA did state that technical feasibility should be evaluated on a case-by-case basis. This control option is discussed in greater detail below per USEPA guidance.

CCS is a developing technology that requires three distinct processes:

- removal of CO_2 from the exhaust gas;
- transportation of the captured CO_2 to a suitable storage location; and,
- safe and secure storage of the captured and delivered CO_2.

The first step in the CCS process is capture of the CO_2 from the turbine exhaust in a form that is suitable for transport. There are several methods that may be used for capturing CO_2 from gas streams, including chemical and physical absorption, cryogenic separation, and membrane separation. Exhaust streams from combustion turbines have relatively low CO_2 concentrations, typically around five percent, compared to 12 to 15 percent in the exhaust from a coal-fired boiler. Only physical and chemical absorption would be considered technically feasible for a high-volume, low-concentration gas stream such as the exhaust from the combustion turbines.

The next step in the CCS process is transportation of the captured CO_2 to a suitable storage location. Captured CO_2 can be used for enhanced oil recovery or sequestered in deep saline formations and unrecoverable coal seams

Currently, development of commercially available CO_2 storage sites is in its infancy and there are no commercially operating sites available for the storage of CO_2 from the Facility. Louisiana is an area where the suitability of geological formations for CO_2 storage is being studied by the SECARB-USA project, which is funded by the USDOE. There are several proposed projects in Louisiana to sequester CO_2 but there are no known sequestration facilities capable of handling the Project's CO_2 emissions currently in operation within the vicinity of the Project.

Currently, there are no known combustion turbine projects utilizing CCS and, although deemed theoretically feasible by the USEPA, this technology is not available with commercial guarantees for a combustion turbine facility.

3.4.2 Step 2: Technical Feasibility of Potential GHG Control Options

3.4.2.1 Low Carbon-Emitting Fuels

As discussed in Step 1, the lowest emitting fuel that is technically feasible for the combustion turbines is natural gas, which has been selected for the Project.

3.4.2.2 Process Modifications

Waste heat recovery involves installation of a heat recovery system in the combustion turbine exhaust to use the recovered heat for another purpose. This technology is commonly used for power generation to generate steam used to power a steam turbine generator. It is also used for combined heat and power plants to use the steam for heating and cooling purposes. The Project employs waste heat recovery on the Siemens SGT-400 combustion turbines to provide heat to the hot oil system. The hot oil system is used for utility heating of the various energy consuming equipment on the FLNGs including amine regeneration, dehydration regeneration, heavy hydrocarbon vaporization, and feed gas heating. There are no additional uses for waste heat recovered from the power generating turbines. Therefore, the use of heat recovery to provide heat to the hot oil system is a technically feasible BACT option.

Combustion air intake cooling involves cooling the turbine inlet air to increase its density and increase turbine output. A turbine operating in hot weather requires the inlet system and compressor to expend more energy on air intake to reach the amount of air needed for combustion. There are two primary types of inlet air cooling systems, evaporative cooling and mechanical chilling. Evaporative cooling involves spraying fresh water into the inlet air to cool it through evaporation. Evaporative cooling requires fresh water which will not be available at the DWP and therefore was eliminated as a BACT option as technically infeasible. Mechanical chilling requires electricity and operates in a similar manner to air conditioning. The Project evaluated the use of chillers on the combustion turbines but determined that these large heavy pieces of equipment could not be accommodated with the weight restrictions on the offshore platforms and therefore eliminated as technically infeasible.

3.4.2.3 Energy Efficiency

USEPA's 2011 GHG permitting guidance states:

> "*Evaluation of [energy efficiency options] need not include an assessment of each and every conceivable improvement that could marginally improve the energy efficiency of [a] new facility as a whole (e.g., installing more efficient light bulbs in the facility's cafeteria), since the burden of this level of review would likely outweigh any gain in emissions reductions achieved. USEPA instead recommends that the BACT analyses for units at a new facility concentrate on the energy efficiency of equipment that uses the largest amounts of energy, since energy efficient options for such units and equipment (e.g., induced draft fans, electric water pumps) will have a larger impact on reducing the facility's emissions...*"

USEPA also recommends that permit applicants:

> *"propose options that are defined as an overall category or suite of techniques to yield levels of energy utilization that could then be evaluated and judged by the permitting authority and the public against established benchmarks...which represent a high level of performance within an industry."*

With regard to natural gas fired power generation, the combustion turbine is considered to be the most efficient technology available.

The Lake Charles PDS identified an economizer to recover heat from the turbine exhaust gas to preheat boiler feedwater as a technically feasible design measure. The Project does not have boiler feedwater and therefore this is not a technically feasible option.

The Facility's proposed use of advanced combustion turbine technology is the most efficient process technically available to minimize GHG emissions.

3.4.2.4 Carbon Capture and Storage

In USEPA's 2011 GHG BACT guidance, they stated that CCS should generally be considered technically achievable and considered in a GHG PSD BACT analysis for combustion turbines. However, USEPA noted in the 2011 guidance that the guidance was being issued at a time when add-on control technologies for GHGs or emissions sources may be limited in number and in various stages of development and commercialization and that CCS technologies may be more widely applicable in the future. The USEPA noted that "these facts are important to BACT Step 2, wherein technically infeasible control options are eliminated from further consideration." USEPA's GHG BACT guidance document states "to establish that an option is technically infeasible, the permitting record should show that an available control option has neither been demonstrated in practice nor is available and applicable to the source type under review." More than 11 years later, there are currently no known simple cycle combustion turbine projects equipped with CCS or currently proposed to install CCS. CCS has not been demonstrated in practice for a simple cycle combustion turbine.

USEPA 2011 GHG BACT guidance states that "logistical hurdles for CCS may include obtaining contracts for offsite land acquisition (including the availability of land), the need for funding (including, for example, government subsidies), timing of available transportation infrastructure, and developing a site for secure long-term storage." Installing CCS at a DWP includes all of these logistical hurdles, there is space available for a carbon capture system, securing funding for a project type that has never been demonstrated is not feasible, and there are no sites currently available for long term storage of the Project's CO_2.

For the Lake Charles project, LDEQ determined that CCS was technically infeasible due to the numerous technical and legal barriers hindering the widespread, cost-effective deployment of this technology.

The most recent PSD GHG BACT determination (July 29, 2022) for a combustion turbine project identified in USEPA's RBLC is for the Lincoln Land Energy Center in Illinois. The Illinois Environmental Protection Agency reviewed carbon capture technologies that have been studied to date by the USDOE's NETL including MEA Scrubbing, Chilled Ammonia, Ammonia Scrubbing, and Gas Separation Membrane Technology and concluded that these technologies have not been demonstrated on combustion turbines and therefore carbon capture is not technically feasible for combustion turbines.

The most recent determination in the RBLC for a LNG liquefaction facility was for the AGDC with a permit issued on July 7, 2022. The Alaska Department of Environmental Conservation determined that CCS was not technically feasible for any of the project's GHG emission sources.

Per USEPA guidance, the permitting record shows that CCS has never been demonstrated in practice for a large combustion turbine and is not available for a combustion turbine. There are no known combustion turbine projects that have proposed CCS and the most recent PSD GHG BACT determination confirms that carbon capture is not technically feasible for a combustion turbine. Consistent with USEPA's BACT guidance, CCS has been determined to be technically infeasible for the Project's simple cycle combustion turbines and therefore eliminated as a BACT option.

3.4.3 Step 3: Ranking of Technically Feasible GHG Control Options by Effectiveness

The technically feasible options are as follows:

- low emitting fuels;
- efficient design; and,
- combustion and efficiency measures.

The combination of all technically feasible control measures is the top-ranked control option.

3.4.4 Step 4: Evaluation of Most Effective Controls

All technically feasible control measures is the top-ranked control option and proposed as BACT for the Project. Therefore, an evaluation of the economic, environmental, and energy impacts of these options are not needed.

3.4.5 Step 5: Selection of BACT

The Project proposes the following control measures a GHG BACT for the power generating combustion turbines:

- firing natural gas, which is the lowest emitting fuel available for the combustion turbines;
- efficient Project design to minimize energy consumption; and
- use advanced combustion turbine technology which is the most efficient technology for natural gas power generation.

A review of enforceable GHG emission limits for simple cycle power generating turbines shows mostly annual tpy limits have been permitted. The Project proposes to limit annual GHG emissions from each combustion turbine as follows:

- Siemens SGT-400: 89,152 tpy per turbine

The AGDC permit included a short term GHG emission limit, as CO_2e, of 117.1 lb/MMBtu for simple cycle combustion turbines. The Project will be required to report GHG emission in accordance with 40 CFR 98, Subpart C which is based upon the emission factors provided in Tables 1 and 2 of this subpart and the global warming potentials GWPs provided in 40 CFR 98, Subpart A. The current emission factors and GWPs are equal to an emission rate of 117.0 lb/MMBtu. However, the GWPs and emission factors in 40 CFR 98 are subject to change and may increase or lower in the future. The Project proposes to comply with the applicable GWPs and emission factors in 40 CFR 98, Subparts A and C in effect for each reporting year.

A review of PSD GHG BACT precedents for combustion turbine projects was conducted to identify operating practices, efficiency measures, and compliance monitoring. The most applicable precents identified were for the Lake Charles project and includes:

- Operation in accordance with vendor recommendations including periodic tune-ups and maintenance for optimal thermal efficiency.
- Advanced combustion controls to maintain optimum excess air.
- Good combustion practices, meaning complete combustion of the natural gas as demonstrated through compliance with the CO BACT limit.

3.5 THERMAL OXIDIZERS

3.5.1 Step 1: Identify GHG Control Options

Emission reductions can be achieved through the following three measures:

- A change in raw materials where substitution to a lower emitting raw material may be technically feasible.
- Process modifications where a change in the process may result in lower emissions.
- Add-on control equipment to capture and reduce emissions.

3.5.1.1 Raw Materials

The thermal oxidizers control emissions of hydrogen sulfide and residual hydrocarbons in the waste gas from the amine stripper column on the gas treatment. There are no known changes in raw materials that would reduce GHG emissions from the thermal oxidizer.

3.5.1.2 Process Modifications

Process modifications considered for the thermal oxidizers include the following:

- waste heat recovery; and
- design and combustion efficiency measures.

Waste heat recovery involves installation of a heat recovery system in the exhaust to use the recovered heat for another purpose. The Project employs waste heat recovery on the Siemens SGT-400 combustion turbines to provide heat to the hot oil system. The hot oil system is used for utility heating of the various energy consuming equipment on the FLNGs including amine regeneration, dehydration regeneration, heavy hydrocarbon vaporization, and feed gas heating. There are no additional uses for waste heat recovered from the thermal oxidizers.

The thermal oxidizers implement advanced combustion design and have a vendor guarantee of 99.9 percent oxidation of contaminants in the acid gas, including methane. Complete combustion of methane reduces GHG emissions as the GWP of methane is 25 times greater than for CO_2. However, during normal operation, 91.5 percent of the CO_2 emissions from the thermal oxidizers is CO_2 in the acid gas that simply passes through the thermal oxidizer.

The Applicant will operate and maintain all Project equipment in accordance with manufacture specifications and recommendations to ensure that it operates near design efficiency through the life of the Project.

3.5.1.3 Add-on Controls

CCS

There are limited post-combustion options for controlling CO_2. The USEPA indicated in *PSD and Title V Permitting Guidance for Greenhouse Gases* (USEPA 2011) that carbon capture and sequestration (CCS) should be considered in Step 1 of a top-down BACT analysis and evaluated in Step 2 of the process. USEPA did state that technical feasibility should be evaluated on a case-by-case basis. This control option is discussed in greater detail below per USEPA guidance.

CCS is a developing technology that requires three distinct processes:

- removal of CO_2 from the exhaust gas;
- transportation of the captured CO_2 to a suitable storage location; and,
- safe and secure storage of the captured and delivered CO_2.

The first step in the CCS process is capture of the CO_2 from the exhaust in a form that is suitable for transport. There are several methods that may be used for capturing CO_2 from gas streams, including chemical and physical absorption, cryogenic separation, and membrane separation.

The next step in the CCS process is transportation of the captured CO_2 to a suitable storage location. Captured CO_2 can be used for enhanced oil recovery or sequestered in deep saline formations and unrecoverable coal seams Currently, development of commercially available CO_2 storage sites is in its infancy and there are no commercially operating sites available for the storage of CO_2 from the Facility. Louisiana is an area where the suitability of geological formations for CO_2 storage is being studied by the SECARB-USA project, which is funded by the USDOE. There are several proposed projects in Louisiana to sequester CO_2 but there are no known sequestration facilities capable of handling the Project's CO_2 emissions currently in operation within the vicinity of the Project.

Currently, there are no known thermal oxidizers utilizing CCS and, although deemed theoretically feasible by the USEPA, this technology is not available with commercial guarantees for a thermal oxidizer.

3.5.2 Step 2: Technical Feasibility of Potential GHG Control Options

3.5.2.1 Low Carbon-Emitting Materials

As discussed in Step 1, the thermal oxidizer controls emissions of hydrogen sulfide and residual hydrocarbons in the waste gas from the amine stripper column on the gas treatment. There are no known changes in raw materials that would reduce GHG emissions from the thermal oxidizer and this is not a technically feasible control option.

3.5.2.2 Process Modifications

There will be no useful purpose for any recovered heat from the thermal oxidizer exhausts and therefore this is not a technically feasible control option.

3.5.2.3 Combustion Efficiency

The Facility's proposed use of advanced combustion technology to oxidize 99.9 percent of the contaminants in the exhaust gas is the most efficient technology to minimize GHG emissions.

3.5.2.4 Carbon Capture and Storage

A review of CCS studies available from the USEPA, USDOE, and NETL did not identify a single consideration of CCS to control GHG emissions from a thermal oxidizer in use at any facility type. The permitting agencies for the Lake Charles and AGDC projects concluded that CCS was not technically feasible for the thermal oxidizers.

USEPA's GHG BACT guidance document states "to establish that an option is technically infeasible, the permitting record should show that an available control option has neither been demonstrated in practice nor is available and applicable to the source type under review." There are currently no known thermal oxidizers equipped with CCS or currently proposed to install CCS. Based upon available information, it is not believed that CCS for a thermal oxidizer has ever been evaluated.

Per USEPA guidance, the permitting record shows that CCS has never been demonstrated in practice and is not available for the thermal oxidizer. Consistent with USEPA's BACT guidance, CCS has been determined to be technically infeasible for the thermal oxidizers.

3.5.3 Step 3: Ranking of Technically Feasible GHG Control Options by Effectiveness

The technically feasible options are as follows:

- combustion efficiency.

3.5.4 Step 4: Evaluation of Most Effective Controls

Combustion efficiency is the sole technically feasible option and therefore the top control option. Therefore, an evaluation of the economic, environmental, and energy impacts of these options are not needed.

3.5.5 Step 5: Selection of BACT

The Project proposes the following control measures a GHG BACT for the thermal oxdiizers:

- use advanced combustion technology designed to oxidize 99.9% of the methane in the acid gas.

A review of enforceable GHG emission limits for thermal oxidizers shows only annual tpy limits have been permitted. The Project proposes to limit annual GHG emissions from each oxidizer as follows:

- 92,292 tpy per oxidizer

A review of PSD GHG BACT precedents for LNG liquefaction plant projects was conducted to identify operating practices, efficiency measures, and compliance monitoring for the thermal oxidizers. The most applicable precents identified were for the Lake Charles project and includes:

- Operation in accordance with vendor recommendations including periodic tune-ups and maintenance for optimal combustion efficiency.
- Good combustion practices, meaning complete combustion of the natural gas as demonstrated through compliance with the CO BACT limit.

3.6 WET AND DRY FLARES

3.6.1 Step 1: Identify GHG Control Options

Emission reductions can be achieved through the following three measures:

- A change in raw materials where substitution to a lower emitting raw material may be technically feasible.
- Process modifications where a change in the process may result in lower emissions.
- Add-on control equipment to capture and reduce emissions.

3.6.1.1 Raw Materials

The wet and dry flares control emissions of natural gas released during upset conditions, such as the effluent from pressure relief valves and the blowdown system. There are no changes in raw materials available to reduce GHG emissions.

3.6.1.2 Process Modifications

Process modifications considered for the flares include the following:

- waste heat recovery; and
- design and combustion efficiency measures.

Waste heat recovery involves installation of a heat recovery system in the exhaust to use the recovered heat for another purpose. The Project employs waste heat recovery on the Siemens SGT-400 combustion turbines to provide heat to the hot oil system. The hot oil system is used for utility heating of the various energy consuming equipment on the FLNGs including amine regeneration, dehydration regeneration, heavy hydrocarbon vaporization, and feed gas heating. There are no additional uses for waste heat recovered from the flares. Further, the flares only operate during upset conditions and therefore waste heat could not be used.

The flares implement advanced combustion design and have a vendor guarantee of 99 percent oxidation of contaminants in the acid gas, including methane. Complete combustion of methane reduces GHG emissions as the GWP of methane is 25 times greater than for CO_2.

The Applicant will operate and maintain all Project equipment in accordance with manufacture specifications and recommendations to ensure that it operates near design efficiency through the life of the Project.

3.6.1.3 Add-on Controls

Carbon Capture and Sequestration ("CCS")

There are limited post-combustion options for controlling CO_2. The USEPA indicated in *PSD and Title V Permitting Guidance for Greenhouse Gases* (USEPA 2011) that carbon capture and sequestration (CCS) should be considered in Step 1 of a top-down BACT analysis and evaluated in Step 2 of the process. USEPA did state that technical feasibility should be evaluated on a case-by-case basis. This control option is discussed in greater detail below per USEPA guidance.

CCS is a developing technology that requires three distinct processes:

- removal of CO_2 from the exhaust gas;
- transportation of the captured CO_2 to a suitable storage location; and,
- safe and secure storage of the captured and delivered CO_2.

The first step in the CCS process is capture of the CO_2 from the exhaust in a form that is suitable for transport. There are several methods that may be used for capturing CO_2 from gas streams, including chemical and physical absorption, cryogenic separation, and membrane separation.

The next step in the CCS process is transportation of the captured CO_2 to a suitable storage location. Captured CO_2 can be used for enhanced oil recovery or sequestered in deep saline formations and unrecoverable coal seams Currently, development of commercially available CO_2 storage sites is in its infancy and there are no commercially operating sites available for the storage of CO_2 from the Facility. Louisiana is an area where the suitability of geological formations for CO_2 storage is being studied by the SECARB-USA project, which is funded by the USDOE. There are several proposed projects in Louisiana to sequester CO_2 but there are no known sequestration facilities capable of handling the Project's CO_2 emissions currently in operation within the vicinity of the Project.

Currently, there are no known flares utilizing CCS and, although deemed theoretically feasible by the USEPA, this technology is not available with commercial guarantees for a flare.

Gas Recovery System

A gas recovery system would capture the gas and return it to the fuel system. The gas recovery system would be similar to the Project's compression system and include recovery gas compressors, flow controls, and piping systems.

3.6.1.4 Step 2: Technical Feasibility of Potential GHG Control Options

Low Carbon-Emitting Materials

As discussed in Step 1, there are no known changes in raw materials that would reduce GHG emissions from the flares and this is not a technically feasible control option.

Process Modifications

There will be no useful purpose for any recovered heat from the flare exhausts and therefore this is not a technically feasible control option.

Combustion Efficiency

The Project's proposed use of advanced combustion technology to oxidize 99 percent of the contaminants in the gas is the most efficient technology to minimize GHG emissions.

Carbon Capture and Storage

A review of CCS studies available from the USEPA, USDOE, and NETL did not identify a single consideration of CCS to control GHG emissions from a flare in use at any facility type. The permitting agencies for the Lake Charles and AGDC projects concluded that CCS was not technically feasible for the flares. The flares will only be operated during startup, shutdown and process upsets and therefore add-on controls of any kind are not suitable for the flares.

USEPA's GHG BACT guidance document states "to establish that an option is technically infeasible, the permitting record should show that an available control option has neither been demonstrated in practice nor is available and applicable to the source type under review." There are currently no known flares equipped with CCS or currently proposed to install CCS. Based upon available information, it is not believed that CCS for a flare has ever been evaluated.

Per USEPA guidance, the permitting record shows that CCS has never been demonstrated in practice and is not available for the flares. Consistent with USEPA's BACT guidance, CCS has been determined to be technically infeasible for the flares.

Gas Recovery System

As the flares would only operate during startup, shutdown, and process upsets, it's unlikely that a gas recovery system would be readily available for these unplanned events, especially shutdowns and process upsets. The permitting agencies for Lake Charles and AGDC determined that a gas recovery system would be technically infeasible due to the sporadic nature of the gases controlled. For these reasons, gas recovery was determined to be technically infeasible.

3.6.1.5 Step 3: Ranking of Technically Feasible GHG Control Options by Effectiveness

The technically feasible options are as follows:

- combustion efficiency.

3.6.1.6 Step 4: Evaluation of Most Effective Controls

Combustion efficiency is the sole technically feasible option and therefore the top control option. Therefore, an evaluation of the economic, environmental, and energy impacts of these options are not needed.

3.6.1.7 Step 5: Selection of BACT

The Project proposes the following control measures a GHG BACT for the flares:

- use advanced combustion technology designed to oxidize 99% of the methane in the gas. The flares will meet the minim design requirements under 40 CFR 60.18 (c) through (f).

A review of enforceable GHG emission limits for flares shows only annual tpy limits have been permitted. The Project proposes to limit annual GHG emissions the flares as follows:

- Dry Flares: 31,328 tpy per flare

- Wet Flares: 32,383 tpy per flare

A review of PSD GHG BACT precedents for LNG liquefaction plant projects was conducted to identify operating practices, efficiency measures, and compliance monitoring for the flares. The most applicable precents identified were for the Lake Charles project and includes:

- Operation in accordance with vendor recommendations including periodic tune-ups and maintenance for optimal combustion efficiency.

3.7 FSU GCU

The GCU is similar in operation to the wet and dry flares as it will only operate during process upsets.

3.7.1 Step 1: Identify GHG Control Options

Emission reductions can be achieved through the following three measures:

- A change in raw materials where substitution to a lower emitting raw material may be technically feasible.
- Process modifications where a change in the process may result in lower emissions.
- Add-on control equipment to capture and reduce emissions.

3.7.1.1 Raw Materials

The GCU controls emissions of BOG released during upset conditions, such as during gas freeing and purging procedures. There are no changes in raw materials available to reduce GHG emissions.

3.7.1.2 Process Modifications

Process modifications considered for the flares include the following:

- waste heat recovery; and
- design and combustion efficiency measures.

Waste heat recovery involves installation of a heat recovery system in the exhaust to use the recovered heat for another purpose. The Project employs waste heat recovery on the Siemens SGT-400 combustion turbines to provide heat to the hot oil system. The hot oil system is used for utility heating of the various energy consuming equipment on the FLNGs including amine regeneration, dehydration regeneration, heavy hydrocarbon vaporization, and feed gas heating. There are no additional uses for waste heat recovered from the GCU. Further, the GCU only operates during upset conditions and therefore waste heat could not be used.

The GCU implements advanced combustion design and have a vendor guarantee of 99 percent oxidation of contaminants in the BOG, including methane. Complete combustion of methane reduces GHG emissions as the GWP of methane is 25 times greater than for CO_2.

The Applicant will operate and maintain all Project equipment in accordance with manufacture specifications and recommendations to ensure that it operates near design efficiency through the life of the Project.

3.7.1.3 Add-on Controls

<u>CCS</u>

There are limited post-combustion options for controlling CO_2. The USEPA indicated in *PSD and Title V Permitting Guidance for Greenhouse Gases* (USEPA 2011) that carbon capture and sequestration (CCS) should be considered in Step 1 of a top-down BACT analysis and evaluated in Step 2 of the process. USEPA did state that technical feasibility should be evaluated on a case-by-case basis. This control option is discussed in greater detail below per USEPA guidance.

CCS is a developing technology that requires three distinct processes:

- removal of CO_2 from the exhaust gas;
- transportation of the captured CO_2 to a suitable storage location; and,
- safe and secure storage of the captured and delivered CO_2.

The first step in the CCS process is capture of the CO_2 from the exhaust in a form that is suitable for transport. There are several methods that may be used for capturing CO_2 from gas streams, including chemical and physical absorption, cryogenic separation, and membrane separation.

The next step in the CCS process is transportation of the captured CO_2 to a suitable storage location. Captured CO_2 can be used for enhanced oil recovery or sequestered in deep saline formations and unrecoverable coal seams Currently, development of commercially available CO_2 storage sites is in its infancy and there are no commercially operating sites available for the storage of CO_2 from the Facility. Louisiana is an area where the suitability of geological formations for CO_2 storage is being studied by the SECARB-USA project, which is funded by the USDOE. There are several proposed projects in Louisiana to sequester CO_2 but there are no known sequestration facilities capable of handling the Project's CO_2 emissions currently in operation within the vicinity of the Project.

Currently, there are no known GCUs utilizing CCS and, although deemed theoretically feasible by the USEPA, this technology is not available with commercial guarantees for a flare.

<u>Gas Recovery System</u>

A gas recovery system would capture the BOG and return it to the fuel system. The gas recovery system would be similar to the Project's compression system and include recovery gas compressors, flow controls, and piping systems.

3.7.1.4 Step 2: Technical Feasibility of Potential GHG Control Options

Low Carbon-Emitting Materials

As discussed in Step 1, there are no known changes in raw materials that would reduce GHG emissions from the flares and this is not a technically feasible control option.

Process Modifications

There will be no useful purpose for any recovered heat from the GCU exhaust and therefore this is not a technically feasible control option.

Combustion Efficiency

The Project's proposed use of advanced combustion technology to oxidize 99 percent of the contaminants in the BOG is the most efficient technology to minimize GHG emissions.

Carbon Capture and Storage

A review of CCS studies available from the USEPA, USDOE, and NETL did not identify a single consideration of CCS to control GHG emissions from a GCU, or flare, in use at any facility type. The GCU will only be operated during process upsets and therefore add-on controls are not suitable.

USEPA's GHG BACT guidance document states "to establish that an option is technically infeasible, the permitting record should show that an available control option has neither been demonstrated in practice nor is available and applicable to the source type under review." There are currently no known GCUs, or flares, equipped with CCS or currently proposed to install CCS. Based upon available information, it is not believed that CCS for a GCU has ever been evaluated.

Per USEPA guidance, the permitting record shows that CCS has never been demonstrated in practice and is not available for the GCU. Consistent with USEPA's BACT guidance, CCS has been determined to be technically infeasible for the GCU.

Gas Recovery System

As the GCU would only operate during process upsets, it's unlikely that a gas recovery system would be readily available for these unplanned events. For this reason, gas recovery was determined to be technically infeasible.

3.7.1.5 Step 3: Ranking of Technically Feasible GHG Control Options by Effectiveness

The technically feasible options are as follows:

- combustion efficiency.

3.7.1.6 Step 4: Evaluation of Most Effective Controls

Combustion efficiency is the sole technically feasible option and therefore the top control option. Therefore, an evaluation of the economic, environmental, and energy impacts of these options are not needed.

3.7.1.7 Step 5: Selection of BACT

The Project proposes the following control measures a GHG BACT for the GCU:

- use advanced combustion technology designed to oxidize 99% of the methane in the acid gas. The flares will meet the minim design requirements under 40 CFR 60.18 (c) through (f).

A review of enforceable GHG emission limits for GCUs did not identify any precents. Since operation of the GCU is similar to that of the flares, the Project proposes to limit annual GHG emissions from the GCU as follows:

- 1,797 tpy

A review of PSD GHG BACT precedents for LNG liquefaction plant projects was conducted to identify operating practices, efficiency measures, and compliance monitoring for the GCU and none were identified. As operation of the GCU is similar to that of the flares, the proposed compliance methods are the same as those for the flares:

- Operation in accordance with vendor recommendations including periodic tune-ups and maintenance for optimal combustion efficiency.

3.8 FSU BOILERS

3.8.1 Step 1: Identify GHG Control Options

Emission reductions can be achieved through the following three measures:

- A change in raw materials where substitution to a lower emitting raw material may be technically feasible.
- Process modifications where a change in the process may result in lower emissions.
- Add-on control equipment to capture and reduce emissions.

3.8.1.1 Raw Materials

For the Project, the "raw material" would be the fuel combusted in the FSU boilers. Fuels that can be combusted in the boiler are fuel oil and natural gas. The boilers will operate to supply steam for cargo operations including gas heaters, glycol water heater, and general heating services. The boilers will be fired with marine fuel oil which is available as a stand-alone fuel source on the FSU.

3.8.1.2 Process Modifications

Process modifications considered for the boilers include the following:

- design and operational efficiency measures.

The boilers are small package boilers with meeting current small boiler design standards to achieve high combustion efficiency. Complete combustion of the fuel oil results in more useful energy and thereby ensures high efficiency operation. By utilizing more efficient technology, less fuel is required to produce the same amount of output. There are no know process modifications that could reduce GHG emissions from the boilers.

The Applicant will operate and maintain all Project equipment in accordance with manufacture specifications and recommendations to ensure that it operates near design efficiency through the life of the Project.

3.8.1.3 Add-on Controls

<u>CCS</u>

There are limited post-combustion options for controlling CO_2. The USEPA indicated in *PSD and Title V Permitting Guidance for Greenhouse Gases* (USEPA 2011) that carbon capture and sequestration (CCS) should be considered in Step 1 of a top-down BACT analysis and evaluated in Step 2 of the process. USEPA did state that technical feasibility should be evaluated on a case-by-case basis. This control option is discussed in greater detail below per USEPA guidance.

CCS is a developing technology that requires three distinct processes:

- removal of CO_2 from the exhaust gas;
- transportation of the captured CO_2 to a suitable storage location; and,
- safe and secure storage of the captured and delivered CO_2.

The first step in the CCS process is capture of the CO_2 from the exhaust in a form that is suitable for transport. There are several methods that may be used for capturing CO_2 from gas streams, including chemical and physical absorption, cryogenic separation, and membrane separation.

The next step in the CCS process is transportation of the captured CO_2 to a suitable storage location. Captured CO_2 can be used for enhanced oil recovery or sequestered in deep saline formations and unrecoverable coal seams Currently, development of commercially available CO_2 storage sites is in its infancy and there are no commercially operating sites available for the storage of CO_2 from the Facility. Louisiana is an area where the suitability of geological formations for CO_2 storage is being studied by the Southeast Regional CO_2 Utilization and Storage Acceleration Partnership ("SECARB-USA") project, which is funded by the United States Department of Energy ("USDOE"). There are several proposed projects in Louisiana to sequester CO_2 but there are no known sequestration facilities capable of handling the Project's CO_2 emissions currently in operation within the vicinity of the Project.

Currently, there are no known small package boilers utilizing CCS.

3.8.2 Step 2: Technical Feasibility of Potential GHG Control Options

3.8.2.1 Low Carbon-Emitting Fuels

The boilers will fire marine fuel oil as it is a readily available stand-alone fuel source which is required for the critical operation of the boilers to supply steam for cargo operations including gas heaters, glycol water heater, and general heating services. The boilers are required to have a standalone ready to fire fuel and therefore are fired with oil rather than natural gas.

3.8.2.2 Process Modifications

Proper design of the boilers to achieve a high combustion efficiency is technically feasible.

3.8.2.3 Carbon Capture and Storage

In USEPA's 2011 GHG BACT guidance, they stated that a permitting authority may make a determination to dismiss CCS for a small package boiler on grounds that no reasonable opportunity exists for the capture and long-term storage or reuse of captured CO_2. CCS has been dismissed as technically infeasible for all of the Project's largest GHG emission sources. The small package boilers account for only 0.5 percent of the Projects total GHG emissions. As CCS was not technically feasible for the Project's much larger GHG sources, it is not technically feasible for the package boilers.

3.8.3 Step 3: Ranking of Technically Feasible GHG Control Options by Effectiveness

The technically feasible options are as follows:

- low emitting fuels;
- combustion efficiency measures.

The combination of all technically feasible control measures is the top-ranked control option.

3.8.4 Step 4: Evaluation of Most Effective Controls

All technically feasible control measures is the top-ranked control option and proposed as BACT for the Project. Natural gas was not selected as the fuel for the boilers as a stand-alone fuel source is needed to ensure availability of the boilers. In the event of a process upset, natural gas supply cannot be ensured and therefore fuel oil was selected. The boilers are required to have a standalone ready to fire fuel and therefore are fired with oil rather than natural gas.

3.8.5 Step 5: Selection of BACT

The Project proposes the following control measures a GHG BACT for the package boilers:

- Proper boiler design to achieve a high combustion efficiency of the fuel.

A review of enforceable GHG emission limits for package boiler shows predominantly annual tpy limits have been permitted. The Project proposes to limit annual GHG emissions from the boilers as follows:

- 3,833 tpy per boiler

A review of PSD GHG BACT precedents for package boilers was conducted to identify operating practices, efficiency measures, and compliance monitoring and no precedents were identified. The Project proposes the following:

- Operation in accordance with vendor recommendations including periodic tune-ups and maintenance for optimal thermal efficiency.
- Good combustion practices, meaning complete combustion of the fuel oil through operation of the boiler in accordance with vendor recommendations.

3.9 EMERGENCY ENGINES

The 14 emergency generator engines and 8 emergency fire pump engines are considered together as they are all emergency compression reciprocating internal combustion engines subject to New Source Performance Standard ("NSPS") Subpart IIII and therefore limited to non-emergency operation of no more than 100 hours per year.

3.9.1 Step 1: Identify GHG Control Options

Emission reductions can be achieved through the following three measures:

- A change in raw materials where substitution to a lower emitting raw material may be technically feasible.
- Process modifications where a change in the process may result in lower emissions.
- Add-on control equipment to capture and reduce emissions.

3.9.1.1 Raw Materials

For the Project, the "raw material" would be the fuel combusted in the engines. Emergency engines require a stand-alone fuel source to be ready to operate in the event of an emergency. The fuel available for the emergency engines is diesel fuel oil.

3.9.1.2 Process Modifications

Process modifications considered for the boilers include the following:

- design and operational efficiency measures.

The engines are all subject to NSPS Subpart IIII which imposes emission limitations and certification of compliance by the vendor. Proper engine design to comply with NSPS Subpart IIII is technically feasible.

3.9.1.3 Add-on Controls

CCS

There are limited post-combustion options for controlling CO_2. The USEPA indicated in *PSD and Title V Permitting Guidance for Greenhouse Gases* (USEPA 2011) that carbon capture and sequestration (CCS) should be considered in Step 1 of a top-down BACT analysis and evaluated in Step 2 of the process. USEPA did state that technical feasibility should be evaluated on a case-by-case basis. This control option is discussed in greater detail below per USEPA guidance.

CCS is a developing technology that requires three distinct processes:

- removal of CO_2 from the exhaust gas;
- transportation of the captured CO_2 to a suitable storage location; and,
- safe and secure storage of the captured and delivered CO_2.

The first step in the CCS process is capture of the CO_2 from the exhaust in a form that is suitable for transport. There are several methods that may be used for capturing CO_2 from gas streams, including chemical and physical absorption, cryogenic separation, and membrane separation.

The next step in the CCS process is transportation of the captured CO_2 to a suitable storage location. Captured CO_2 can be used for enhanced oil recovery or sequestered in deep saline formations and unrecoverable coal seams Currently, development of commercially available CO_2 storage sites is in its infancy and there are no commercially operating sites available for the storage of CO_2 from the Facility. Louisiana is an area where the suitability of geological formations for CO_2 storage is being studied by the Southeast Regional CO_2 Utilization and Storage

Acceleration Partnership ("SECARB-USA") project, which is funded by the United States Department of Energy ("USDOE"). There are several proposed projects in Louisiana to sequester CO_2 but there are no known sequestration facilities capable of handling the Project's CO_2 emissions currently in operation within the vicinity of the Project.

There are no known emergency engines utilizing CCS.

3.9.2 Step 2: Technical Feasibility of Potential GHG Control Options

3.9.2.1 Low Carbon-Emitting Fuels

The engines will fire diesel oil which is the sole stand-alone fuel available for the engines.

3.9.2.2 Process Modifications

Proper design of the engines to achieve a high combustion efficiency is technically feasible.

3.9.2.3 Carbon Capture and Storage

The emergency engines will operate for no more than 100 hours per year in non-emergency operation and therefore, add-on controls are not technically feasible. The permitting agencies for the Lake Charles and AGDC projects determined that CCS was not technically feasible for the emergency engines for this reason.

3.9.3 Step 3: Ranking of Technically Feasible GHG Control Options by Effectiveness

The technically feasible options are as follows:

- combustion efficiency measures.

3.9.4 Step 4: Evaluation of Most Effective Controls

Combustion efficiency is the sole control option and proposed as BACT for the Project.

3.9.5 Step 5: Selection of BACT

The Project proposes the following control measures a GHG BACT for the emergency engines:

- Proper engine design to achieve a high combustion efficiency of the fuel.

A review of enforceable GHG emission limits for emergency engines shows predominantly annual tpy limits or operating hour limitations. The Project proposes to limit annual GHG emissions from the engines by limiting non-emergency operation to no more than 100 hours per year in accordance with NSPS Subpart IIII

A review of PSD GHG BACT precedents for emergency engines was conducted to identify operating practices, efficiency measures, and compliance monitoring. The Project proposes the following:

- Operation in accordance with vendor recommendations including periodic tune-ups and maintenance for optimal thermal efficiency.
- Good combustion practices, meaning complete combustion of the fuel oil through operation of the boiler in accordance with vendor recommendations.

3.10 FUGITIVE EMISSIONS

The Facility will include natural gas handling systems that will emit GHGs due to fugitive losses of natural gas based upon USEPA emission factors. Estimated fugitive GHG emissions from the natural gas handling equipment are estimated to be 174 tpy as CO_2e, which represents approximately 0.01 percent of the total GHG emissions for the Facility.

3.10.1 Step 1: Identify GHG Control Options

Available control measures for fugitive GHG emissions includes the following:

- Instrument Leak Detection and Repair ("LDAR")
- LDAR With Remote Sensing Technology
- Audio, Visual, and Olfactory ("AVO") Detection and Repair
- Design of Components to minimize leaks

Instrument LDAR provides for monitoring of natural gas components using a portable handheld analyzer.

LDAR with Remote Sensing Technology involves remote sensing of leaks using infrared cameras.

AVO involves physical inspection of natural gas handling equipment to identify leaks.

Design of Components involves proper design of the natural gas handing equipment and the use of high quality compatible components.

3.10.2 Step 2: Technical Feasibility of Potential GHG Control Options

All control measures identified in Step 1 are technically feasible.

3.10.3 Step 3: Ranking of Technically Feasible GHG Control Options by Effectiveness

The ranking of technically feasible control options is as follows:

- Instrument LDAR
- Remote Sensing LDAR
- AVO
- Equipment Design

3.10.4 Step 4: Evaluation of Most Effective Controls

Instrument LDAR and Remote Sensing LDAR are inappropriate for the magnitude of fugitive emissions, which are estimated to be 596 tpy of GHGs and less than 2 tpy of VOCs. The Texas Commission for Environmental Quality's ("TCEQ") current BACT guidance for fugitive sources with less than 10 tpy of VOC emissions is no monitoring. The Project proposes to use AVO and Equipment Design. AVO will be implemented in general accordance with TCEQ's fugitive emissions monitoring approach 28NG (Piping, Valves, Pumps, and Compressors - Pipeline Natural Gas Service).

3.10.5 Step 5: Selection of BACT

The Project proposes the following control measures a GHG BACT for fugitive emissions:

- Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable American National Standards Institute (ANSI), American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), or equivalent codes.
- To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be located to be reasonably accessible for leak-checking during operation. If an unsafe to monitor component is not considered safe to monitor within a calendar year, then it shall be monitored as soon as possible during safe to monitor times. A difficult to monitor component for which quarterly monitoring is specified may instead be monitored annually. The unsafe-to-monitor and difficult-to-monitor components may be identified by one or more of the following methods:
  1) piping and instrumentation diagram (PID);
  2) a written or electronic database or electronic file;
  3) color coding;
  4) a form of weatherproof identification; or
  5) designation of exempted process unit boundaries
- New and reworked piping connections shall be welded or flanged. Screwed connections will only be done on piping smaller than two-inch diameter. Each open-ended valve or line shall be equipped with an appropriately sized cap, blind flange, plug, or a second valve to seal the line.
- At least once every eight hours, an AVO check of reasonably accessible piping components shall be made within the operation area. Should evidence of a leak be found, it shall be checked with a combustible gas indicator (“CGI”) to evaluate severity and determine maintenance actions required to correct the leak.
- Damaged or leaking piping, flanges, connectors, pump and compressor seals found to be leaking shall be tagged and replaced or repaired. A first attempt to repair the leak must be made within 5 days. Records of the first attempt to repair shall be maintained. A leaking component shall be repaired as soon as practicable, but no later than 15 days after the leak is found. If the repair of a component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown provided the leak is less than 15,000 ppmv (above background). If the leak exceeds 15,000 ppmv (above background) and the component cannot be isolated, the system will be shutdown and leak shall be repaired or component replaced to achieve leak free status. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for repair by tagging within 15 days of the detection of the leak.
- Records of repairs shall include date of repairs, repair results, justification for delay of repairs, and corrective actions taken for all components. CGI monitoring shall indicate dates and times, test methods, and instrument readings. Records of physical AVO inspections shall be noted in a logbook or equivalent.

4.0 REFERENCES

USEPA 1990. New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting. United States Environmental Protection Agency. October 1990.

USEPA 2011. PSD and Title V Permitting Guidance for Greenhouse Gases. United States Environmental Protection Agency. March 2011.

Lake Charles LNG Exporting Terminal PSD Permit No. PSD-LA-838.September 3, 2020.

Alaska Gasline Development Corporation Liquefaction Plant PSD Permit AQ1539CPT01 Technical Analysis Report. July 7, 2022.

ATTACHMENT I

COMBUSTION TURBINE SUSD EIQ FORMS

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Sept 2022

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
FLNG1 - CT	**FLNG1 - Compressor Turbine #1 (GE LM6000PF) Startup and Shutdown Emissions**	Method: 18,"Interpolation - Map"; Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 16; Horizontal: 222850.9 mE; Vertical: 3219566.3 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point
no	10.3 ft / ft^2	115.6 ft	129.91 ft/sec	651,046 ft^3/min	929 °F	26 hr/yr	Jan 1 2023	Jan-Mar 25%; Apr-Jun 25%; Jul-Sep 25%; Oct-Dec 25%

Type of Fuel Used and Heat Input (see instructions)

Fuel	Type of Fuel	Heat Input (MMBTU/hr)
a	Natural Gas (as BOG)	482 (HHV, design gas at 59F)
b		
c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	482	Heat Input (MMBTU/hr, HHV)
Maximum Operating Rate/Throughput	493	Heat Input (MMBTU/hr, HHV)
Design Capacity/Volume/Cylinder Displacement	N/A	N/A
Shell Height (ft)	N/A	N/A
Tank Diameter (ft)	N/A	N/A
Tanks: ☐ Fixed Roof	Floating Roof ☐ External	☐ Internal
Date Engine Ordered		Engine Model Year
Date Engine Was Built by Manufacturer		
SI Engines: ☐ **Rich Burn**	☐ **Lean Burn** ☐ **2 Stroke**	☐ **4 Stroke**

Emission Point ID No. (Designation): FLNG1 - CT Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates: Average (lb/hr)	Proposed Emission Rates: Maximum (lbs/hr)	Proposed Emission Rates: Annual (tons/yr)	Permitted Emission Rate (Current): Annual (tons/yr)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
										gr/std ft^3
										ppm by vol
										ppm by vol
Carbon monoxide					33.30					ppm by vol
Total VOC (including those listed below)					2.28					ppm by vol
										ppm by vol
										ppm by vol
										ppm by vol
										ppm by vol

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State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Sept 2022

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
FLNG2 - CT1	**FLNG2 - Compressor Turbine #1 (GE LM6000PF) Startup and Shutdown Emissions**	Method: 18,"Interpolation - Map"; Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 16; Horizontal: 222912.4 mE; Vertical: 3219388.9 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
no	10.3 ft / ft^2	153.4 ft	129.91 ft/sec	651,046 ft^3/min	929 °F	26 hr/yr	Jan 1 2023	25%	25%	25%	25%

Type of Fuel Used and Heat Input (see instructions)

Fuel	Type of Fuel	Heat Input (MMBTU/hr)
a	Natural Gas (as BOG)	482 (HHV, design gas at 59F)
b		
c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	482	Heat Input (MMBTU/hr, HHV)
Maximum Operating Rate/Throughput	483	Heat Input (MMBTU/hr, HHV)
Design Capacity/Volume/Cylinder Displacement	N/A	N/A
Shell Height (ft)	N/A	N/A
Tank Diameter (ft)	N/A	N/A
Tanks: ☐ Fixed Roof	Floating Roof ☐ External	☐ Internal
Date Engine Ordered		Engine Model Year
Date Engine Was Built by Manufacturer		
SI Engines: ☐ **Rich Burn**	☐ **Lean Burn** ☐ **2 Stroke**	☐ **4 Stroke**

Emission Point ID No. (Designation): FLNG2 - CT1 / Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates: Average (lb/hr)	Proposed Emission Rates: Maximum (lbs/hr)	Proposed Emission Rates: Annual (tons/yr)	Permitted Emission Rate (Current): Annual (tons/yr)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Particulate matter (PM_{10})										gr/std ft^3
Sulfur dioxide										ppm by vol
Nitrogen oxides										ppm by vol
Carbon monoxide					33.30					ppm by vol
Total VOC (including those listed below)					2.28					ppm by vol
Lead										ppm by vol
										ppm by vol
										ppm by vol
										ppm by vol
										ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Sept | 2022

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
FLNG1 - PGT1	**FLNG1 - Power Generating Turbine #1 (Siemens SGT-400) Startup and Shutdown Emissions**	Method: 18,"Interpolation - Map"; Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 16; Horizontal: 222750.3 mE; Vertical: 3219680. 6 mN
		Latitude ° ' " hundredths
		Longitude ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point
no	7.00 ft ft^2	154.1 ft	110.27 ft/sec	254,341 ft^3/min	926 °F	8,760 hr/yr	Jan 1 2023	Jan-Mar 25%; Apr-Jun 25%; Jul-Sep 25%; Oct-Dec 25%

Type of Fuel Used and Heat Input (see instructions)

Fuel	Type of Fuel	Heat Input (MMBTU/hr)
a	Natural Gas	174.0 (HHV, design gas at 59F)
b		
c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	174.0	Heat Input (MMBTU/hr, HHV)
Maximum Operating Rate/Throughput	181.2	Heat Input (MMBTU/hr, HHV)
Design Capacity/Volume/Cylinder Displacement	N/A	N/A
Shell Height (ft)	N/A	N/A
Tank Diameter (ft)	N/A	N/A

Tanks: ☐ Fixed Roof | Floating Roof ☐ External ☐ Internal

Date Engine Ordered | | Engine Model Year |

Date Engine Was Built by Manufacturer |

SI Engines: ☐ **Rich Burn** ☐ **Lean Burn** ☐ **2 Stroke** ☐ **4 Stroke**

Emission Point ID No. (Designation): FLNG1 - PGT1 Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates: Average (lb/hr)	Proposed Emission Rates: Maximum (lbs/hr)	Proposed Emission Rates: Annual (tons/yr)	Permitted Emission Rate (Current): Annual (tons/yr)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Particulate matter (PM_{10})										gr/std ft^3
Sulfur dioxide										ppm by vol
Nitrogen oxides										ppm by vol
Carbon monoxide					6.84					ppm by vol
Total VOC (including those listed below)					0.46					ppm by vol
Lead										ppm by vol
										ppm by vol
										ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Sept | 2022

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
FLNG1 - PGT2	**FLNG1 - Power Generating Turbine #2 (Siemens SGT-400) Startup and Shutdown Emissions**	Method 18,"Interpolation - Map" Datum WGS84
Tempo Subject Item ID No.		UTM Zone 16 Horizontal 222757.1 mE Vertical 3219675.2 mN
		Latitude ° ' " hundredths
		Longitude ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
no	7.00 ft / ft^2	154.1 ft	110.27 ft/sec	254,341 ft^3/min	926 °F	8,760 hr/yr	Jan 1 2023	25%	25%	25%	25%

Type of Fuel Used and Heat Input (see instructions)

Fuel	Type of Fuel	Heat Input (MMBTU/hr)
a	Natural Gas	174.0 (HHV, design gas at 59F)
b		
c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	174.0	Heat Input (MMBTU/hr, HHV)
Maximum Operating Rate/Throughput	181.2	Heat Input (MMBTU/hr, HHV)
Design Capacity/Volume/Cylinder Displacement	N/A	N/A
Shell Height (ft)	N/A	N/A
Tank Diameter (ft)	N/A	N/A
Tanks: ☐ Fixed Roof	Floating Roof ☐ External	☐ Internal
Date Engine Ordered		Engine Model Year
Date Engine Was Built by Manufacturer		
SI Engines: ☐ **Rich Burn**	☐ **Lean Burn** ☐ **2 Stroke**	☐ **4 Stroke**

Emission Point ID No. (Designation): FLNG1 - PGT2	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates: Average (lb/hr)	Proposed Emission Rates: Maximum (lbs/hr)	Proposed Emission Rates: Annual (tons/yr)	Permitted Emission Rate (Current): Annual (tons/yr)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant										
Particulate matter (PM_{10})										gr/std ft^3
Sulfur dioxide										ppm by vol
Nitrogen oxides										ppm by vol
Carbon monoxide					6.84					ppm by vol
Total VOC (including those listed below)					0.46					ppm by vol
Lead										ppm by vol
										ppm by vol
										ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Sept 2022

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
FLNG1 - PGT3	**FLNG1 - Power Generating Turbine #3 (Siemens SGT-400) Startup and Shutdown Emissions**	Method: 18,"Interpolation - Map"; Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 16; Horizontal: 222762.9 mE; Vertical: 3219672.2 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point: Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
no	7.0 ft ft^2	154.1 ft	110.27 ft/sec	254,341 ft^3/min	926 °F	8,760 hr/yr	Jan 1 2023	25%	25%	25%	25%

Type of Fuel Used and Heat Input (see instructions)

Fuel	Type of Fuel	Heat Input (MMBTU/hr)
a	Natural Gas	174.0 (HHV, design gas at 59F)
b		
c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	174.0	Heat Input (MMBTU/hr, HHV)
Maximum Operating Rate/Throughput	181.2	Heat Input (MMBTU/hr, HHV)
Design Capacity/Volume/Cylinder Displacement	N/A	N/A
Shell Height (ft)	N/A	N/A
Tank Diameter (ft)	N/A	N/A
Tanks: ☐ Fixed Roof	Floating Roof ☐ External	☐ Internal
Date Engine Ordered		Engine Model Year
Date Engine Was Built by Manufacturer		
SI Engines: ☐ **Rich Burn** ☐ **Lean Burn**	☐ **2 Stroke**	☐ **4 Stroke**

Emission Point ID No. (Designation): FLNG1 - PGT3 Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates: Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Permitted Emission Rate (Current) Annual (tons/yr)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Particulate matter (PM_{10})										gr/std ft^3
Sulfur dioxide										ppm by vol
Nitrogen oxides										ppm by vol
Carbon monoxide					6.84					ppm by vol
Total VOC (including those listed below)					0.46					ppm by vol
Lead										ppm by vol
										ppm by vol
										ppm by vol
										ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Sept | 2022

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
FLNG2 - PGT1	**FLNG2 - Power Generating Turbine #1 (Siemens SGT-400) Startup and Shutdown Emissions**	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 16 Horizontal: 223157.7 mE Vertical: 3219554.6 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point
no	7.0 ft / ft^2	191.9 ft	110.27 ft/sec	254,341 ft^3/min	926 °F	8,760 hr/yr	Jan 1 2023	Jan-Mar 25%; Apr-Jun 25%; Jul-Sep 25%; Oct-Dec 25%

Type of Fuel Used and Heat Input (see instructions)

Fuel	Type of Fuel	Heat Input (MMBTU/hr)
a	Natural Gas	181.2 (HHV, design gas at 59F)
b		
c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	174.0	Heat Input (MMBTU/hr, HHV)
Maximum Operating Rate/Throughput	181.2	Heat Input (MMBTU/hr, HHV)
Design Capacity/Volume/Cylinder Displacement	N/A	N/A
Shell Height (ft)	N/A	N/A
Tank Diameter (ft)	N/A	N/A
Tanks: ☐ Fixed Roof	Floating Roof ☐ External	☐ Internal
Date Engine Ordered		Engine Model Year:
Date Engine Was Built by Manufacturer		
SI Engines: ☐ **Rich Burn**	☐ **Lean Burn** ☐ **2 Stroke**	☐ **4 Stroke**

Emission Point ID No. (Designation): FLNG2 - PGT1 / Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates: Average (lb/hr)	Proposed Emission Rates: Maximum (lbs/hr)	Proposed Emission Rates: Annual (tons/yr)	Permitted Emission Rate (Current): Annual (tons/yr)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Particulate matter (PM_{10})										gr/std ft^3
Sulfur dioxide										ppm by vol
Nitrogen oxides										ppm by vol
Carbon monoxide					6.84					ppm by vol
Total VOC (including those listed below)					0.46					ppm by vol
Lead										ppm by vol
										ppm by vol
										ppm by vol
										ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Sept | 2022

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
FLNG2 - PGT2	FLNG2 - Power Generating Turbine #2 (Siemens SGT-400) Startup and Shutdown Emissions	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 16 Horizontal: 223149.6 mE Vertical: 3219551.5 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point
no	7.0 ft / ___ ft^2	191.9 ft	110.27 ft/sec	254,341 ft^3/min	926 °F	8,760 hr/yr	Jan 1 2023	Jan-Mar 25%; Apr-Jun 25%; Jul-Sep 25%; Oct-Dec 25%

Type of Fuel Used and Heat Input (see instructions)

Fuel	Type of Fuel	Heat Input (MMBTU/hr)
a	Natural Gas	181.2 (HHV, design gas at 59F)
b		
c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	174.0	Heat Input (MMBTU/hr, HHV)
Maximum Operating Rate/Throughput	181.2	Heat Input (MMBTU/hr, HHV)
Design Capacity/Volume/Cylinder Displacement	N/A	N/A
Shell Height (ft)	N/A	N/A
Tank Diameter (ft)	N/A	N/A
Tanks: ☐ Fixed Roof	Floating Roof ☐ External	☐ Internal
Date Engine Ordered		Engine Model Year:
Date Engine Was Built by Manufacturer		
SI Engines: ☐ **Rich Burn**	☐ **Lean Burn** ☐ **2 Stroke**	☐ **4 Stroke**

Emission Point ID No. (Designation): FLNG2 - PGT2 / Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates: Average (lb/hr)	Proposed Emission Rates: Maximum (lbs/hr)	Proposed Emission Rates: Annual (tons/yr)	Permitted Emission Rate (Current) Annual (tons/yr)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Particulate matter (PM_{10})										gr/std ft^3
Sulfur dioxide										ppm by vol
Nitrogen oxides										ppm by vol
Carbon monoxide					6.84					ppm by vol
Total VOC (including those listed below)					0.46					ppm by vol
Lead										ppm by vol
										ppm by vol
										ppm by vol
										ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Sept | 2022

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
FLNG2 - PGT3	**FLNG2 - Power Generating Turbine #3 (Siemens SGT-400) Startup and Shutdown Emissions**	Method: 18,"Interpolation - Map"; Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 16; Horizontal: 223144. 2 mE; Vertical: 3219547.9 mN
		Latitude: ___ ° ___ ' ___ 15 ___ hundredths
		Longitude: ___ ° ___ ' ___ ___ hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
no	7.0 ft / ___ ft^2	191.9 ft	110.27 ft/sec	254,341 ft^3/min	926 °F	8,760 hr/yr	Jan 1 2023	25%	25%	25%	25%

Type of Fuel Used and Heat Input (see instructions)

Fuel	Type of Fuel	Heat Input (MMBTU/hr)
a	Natural Gas	181.2 (HHV, design gas at 59F)
b		
c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	174.0	Heat Input (MMBTU/hr, HHV)
Maximum Operating Rate/Throughput	181.2	Heat Input (MMBTU/hr, HHV)
Design Capacity/Volume/Cylinder Displacement	N/A	N/A
Shell Height (ft)	N/A	N/A
Tank Diameter (ft)	N/A	N/A
Tanks: ☐ Fixed Roof	Floating Roof ☐ External	☐ Internal
Date Engine Ordered		Engine Model Year
Date Engine Was Built by Manufacturer		
SI Engines: ☐ **Rich Burn**	☐ **Lean Burn** ☐ **2 Stroke**	☐ **4 Stroke**

Emission Point ID No. (Designation): FLNG2 - PGT3 / Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates: Average (lb/hr)	Proposed Emission Rates: Maximum (lbs/hr)	Proposed Emission Rates: Annual (tons/yr)	Permitted Emission Rate (Current): Annual (tons/yr)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Particulate matter (PM_{10})										gr/std ft^3
Sulfur dioxide										ppm by vol
Nitrogen oxides										ppm by vol
Carbon monoxide					6.84					ppm by vol
Total VOC (including those listed below)					0.46					ppm by vol
Lead										ppm by vol
										ppm by vol
										ppm by vol
										ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Sept | 2022

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
FLNG2-CT2	FLNG2 - Compressor Turbine #2 (Solar Taurus 70) Startup and Shutdown Emissions	Method: 18,"Interpolation - Map" Datum: WGS84 UTM Zone: 16 Horizontal: 222986.5 mE Vertical: 3219514.3 mN Latitude: ° ' " hundredths Longitude: ° ' " hundredths
Tempo Subject Item ID No.		

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point: Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
no	4.83 ft ft^2	128.0 ft	80.06 ft/sec	88,068 ft^3/min	958 °F	8,760 hr/yr	Jan 1 2023	25%	25%	25%	25%

Type of Fuel Used and Heat Input (see instructions)

Fuel	Type of Fuel	Heat Input (MMBTU/hr)
a	Natural Gas	87.5 (HHV, design gas at 59F)
b		
c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	87.5	Heat Input (MMBTU/hr, HHV)
Maximum Operating Rate/Throughput	89.3	Heat Input (MMBTU/hr, HHV)
Design Capacity/Volume/Cylinder Displacement	N/A	N/A
Shell Height (ft)	N/A	N/A
Tank Diameter (ft)	N/A	N/A
Tanks: ☐ Fixed Roof	Floating Roof ☐ External	☐ Internal
Date Engine Ordered		Engine Model Year
Date Engine Was Built by Manufacturer		
SI Engines: ☐ **Rich Burn**	☐ **Lean Burn** ☐ **2 Stroke**	☐ **4 Stroke**

Emission Point ID No. (Designation): FLNG2-CT2

Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates: Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Permitted Emission Rate (Current): Annual (tons/yr)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Particulate matter (PM_{10})										gr/std ft^3
Sulfur dioxide										ppm by vol
Nitrogen oxides					5.43					ppm by vol
Carbon monoxide					82.5					ppm by vol
Total VOC (including those listed below)					13.5					ppm by vol
Lead										ppm by vol
										ppm by vol
										ppm by vol
										ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Sept | 2022

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
FLNG2-CT3	**FLNG2 - Compressor Turbine #3 (Solar Taurus 70) Startup and Shutdown Emissions**	Method: 18,"Interpolation - Map"; Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 16; Horizontal: 222994.7 mE; Vertical: 3219519.6 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
no	4.83 ft; ft^2	128.0 ft	80.06 ft/sec	88,068 ft^3/min	958 °F	8,760 hr/yr	Jan 1 2023	25%	25%	25%	25%

Type of Fuel Used and Heat Input (see instructions)

Fuel	Type of Fuel	Heat Input (MMBTU/hr)
a	Natural Gas	82.5 (HHV, design gas at 59F)
b		
c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	82.5	Heat Input (MMBTU/hr, HHV)
Maximum Operating Rate/Throughput	82.5	Heat Input (MMBTU/hr, HHV)
Design Capacity/Volume/Cylinder Displacement	N/A	N/A
Shell Height (ft)	N/A	N/A
Tank Diameter (ft)	N/A	N/A
Tanks: ☐ Fixed Roof	Floating Roof ☐ External	☐ Internal
Date Engine Ordered		Engine Model Year
Date Engine Was Built by Manufacturer		
SI Engines: ☐ **Rich Burn**	☐ **Lean Burn** ☐ **2 Stroke**	☐ **4 Stroke**

Emission Point ID No. (Designation): FLNG2-CT3	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				**Average (lb/hr)**	**Maximum (lbs/hr)**	**Annual (tons/yr)**	**Annual (tons/yr)**			
Particulate matter (PM_{10})										gr/std ft^3
Sulfur dioxide										ppm by vol
Nitrogen oxides					5.43					ppm by vol
Carbon monoxide					82.5					ppm by vol
Total VOC (including those listed below)					13.5					ppm by vol
Lead										ppm by vol
										ppm by vol
										ppm by vol
										ppm by vol
										ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Sept | 2022

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
FLNG2-CT4	**FLNG2 - Compressor Turbine #4 (Solar Taurus 70) Startup and Shutdown Emissions**	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 16 Horizontal: 223003 mE Vertical: 3219525 mN
		Latitude: ___ ° ___ ' ___ " ___ hundredths
		Longitude: ___ ° ___ ' ___ " ___ hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point: Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
no	4.83 ft / ___ ft^2	128.0 ft	80.06 ft/sec	88,068 ft^3/min	958 °F	8,760 hr/yr	Jan 1 2023	25%	25%	25%	25%

Type of Fuel Used and Heat Input (see instructions)

Fuel	Type of Fuel	Heat Input (MMBTU/hr)
a	Natural Gas	78.9 (HHV, design gas at 59F)
b		
c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	78.9	Heat Input (MMBTU/hr, HHV)
Maximum Operating Rate/Throughput	80.5	Heat Input (MMBTU/hr, HHV)
Design Capacity/Volume/Cylinder Displacement	N/A	N/A
Shell Height (ft)	N/A	N/A
Tank Diameter (ft)	N/A	N/A
Tanks: ☐ Fixed Roof	Floating Roof ☐ External	☐ Internal
Date Engine Ordered		Engine Model Year
Date Engine Was Built by Manufacturer		
SI Engines: ☐ **Rich Burn**	☐ **Lean Burn** ☐ **2 Stroke**	☐ **4 Stroke**

Pollutant (Emission Point ID No. (Designation): FLNG2-CT4)	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates: Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Permitted Emission Rate (Current): Annual (tons/yr)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Particulate matter (PM_{10})										gr/std ft^3
Sulfur dioxide										ppm by vol
Nitrogen oxides					5.43					ppm by vol
Carbon monoxide					82.5					ppm by vol
Total VOC (including those listed below)					13.5					ppm by vol
Lead										ppm by vol
										ppm by vol
										ppm by vol
										ppm by vol

ATTACHMENT J

FLARE VENDOR VOC CONTROL SPECIFICATION

Zeeco, Inc.
22151 E 91st Street
Broken Arrow, OK 74014
USA

Process Performance Guarantee for Flare System

Zeeco Inc. confirms waste gas destruction efficiency from the flare tips will be 99% or higher when operated and maintained per the operating instructions and industry standards for this type of equipment.

Process performance guarantees outlined in this document for the Dry Flare Package and Wet Flare Package are applicable for the following normal operating gas case scenarios:

Client: NEW FORTRESS ENERGY **Vendor:**
Service: Dry Flare Stack **Site:** OFFSHORE

PROCESS DATA

VAPOR COMPOSITION	Description	DGAA		LGHA		RGLA	
		NORMAL OPERATING (CONTINUOUS PURGING)					
Methane	(Mole %)	94.537	93.29	95.26	94.80	89.906	89.07
Ethane	(Mole %)	0.748	0.40	0.306	0.15	1.836	1.17
Propane	(Mole %)	0.143	0.08	0.155	0.02	0.899	0.89
i-Butane/n-Butane	(Mole %)	0.571	0.50	0.116	0.07	1.061	1.27
i-Pentane/n-Pentane	(Mole %)	0.276	0.42	0.169	0.28	1.429	1.74
Ethylene	(Mole %)		0.00		0.00		0.00
C6+	(Mole %)	0.542	0.85	0.273	0.45	1.192	1.45
Nitrogen	(Mole %)	3.91	4.47	3.719	4.22	3.676	4.42
CO2	(Mole %)	0.001	0.00	0.001	0.00	0.0019	0.00
H2O	(Mole %)		0.00		0.00		0.00
Available pressure at flare inlet	Barg		0.05		0.05		0.05
Average Molecular Weight of Vapor		17.374	17.75	16.92	17.10	19.176	19.63
Condensed Liquid	Sp. Gr. @ Temp. °C		/		/		/
Relief Rate	kg/h		By Supplier		By Supplier		By Supplier
Flowing Temperatures	°C	30.1	65.4	38.3	43.9	30.0	19.6

Client: New Fortress Energy **Vendor:**
Service: Wet Flare Stack **Site:** Offshore

PROCESS DATA

VAPOR COMPOSITION	Description	DGAA	LGHA	RGLA
		Normal Operating (Purging + Continuous Acid Gas)		
Methane	(Mole %)	30.29%	31.59%	27.12%
Ethane	(Mole %)	0.20%	0.19%	0.41%
Propane	(Mole %)	0.03%	0.02%	0.21%
C4s	(Mole %)	0.15%	0.02%	0.34%
C5s	(Mole %)	0.12%	0.07%	0.41%
Ethylene	(Mole %)	0.00%	0.00%	0.00%
C6+	(Mole %)	0.25%	0.13%	0.34%
Nitrogen	(Mole %)	1.29%	1.15%	1.05%
CO2	(Mole %)	65.26%	64.41%	67.57%
H2O	(Mole %)	2.39%	2.40%	2.52%
H2S	(Mole %)	0.02%	0.02%	0.02%
Available pressure at flare inlet	Barg	0.50	0.50	0.50
Average Molecular Weight of Vapor		45.68	34.42	35.88
Condensed Liquid	Sp. Gr. @ Temp. °C	/	/	/
Relief Rate	kg/h	10,815	7,095	7,047
Flowing Temperatures	°C	45.7	39.4	49.3

Process performance guarantees outlined in this document for the Dry Flare Package and Wet Flare Package are applicable under normal ambient conditions of wind, temperature, and relative humidity as listed below.

Maximum Applicable Wind Speed = 6 m/s
Maximum Applicable Temperature = 33.3°C
Maximum Applicable Relative Humidity = 100%

Thank you and Best Regards,

Doug Allen

Doug Allen
Chief Engineer, Zeeco Inc.

ATTACHMENT K

CLARKE EMERGENCY FIRE PUMP ENGINE SPECIFICATIONS

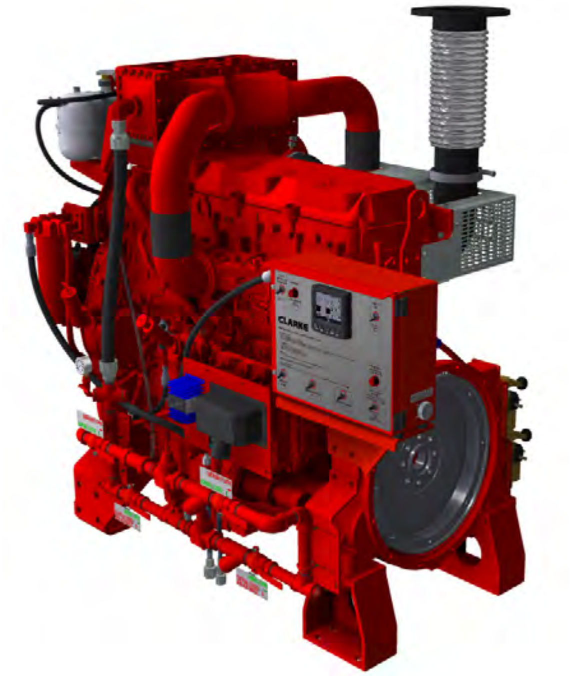
CLARKE®

C13H0 MODELS

UFAD20 UFAD22 UFAD28 UFAD30 UFAD32 UFAD38 UFAD40 UFAD50 UFAD52 UFAD58 UFAD60 UFAD62 UFAD68 UFAD70 UFAD72 UFAD78

UL/FM - cUL APPROVED RATINGS BHP/kW

C13H0 MODEL ♦	RATED SPEED 1470		1760		2100		EMISSIONS
UFAD20					**311**	*232*	EPA Tier 3 Certified
UFAD22	**275**	*205*					EPA Tier 3 Certified
UFAD28			**327**	*244*			EPA Tier 3 Certified
UFAD30					**335**	*250*	EPA Tier 3 Certified
UFAD32	**296**	*221*					EPA Tier 3 Certified
UFAD38			**350**	*261*			EPA Tier 3 Certified
UFAD40					**351**	262	EPA Tier 3 Certified
UFAD50					**399**	*297*	EPA Tier 3 Certified
UFAD52	**351**	*262*					EPA Tier 3 Certified
UFAD58			**380**	*283*			EPA Tier 3 Certified
UFAD60					**425**	*317*	EPA Tier 3 Certified
UFAD62	**384**	*286*					EPA Tier 3 Certified
UFAD68			**422**	*315*			EPA Tier 3 Certified
UFAD70					**460**	*343*	EPA Tier 3 Certified
UFAD72	**398**	*297*					EPA Tier 3 Certified
UFAD78			**455**	*339*			EPA Tier 3 Certified



♦ All Models are available for export

ENGINE SPECIFICATIONS	
Number of Cylinders	6
Aspiration	TRWA
Rotation*	CW
Overall Dimensions - in. (mm)	54.8 (1392) H X 68.9 (1750) L X 45.3 (1150) W
Crankshaft Centerline Height - in. (mm)	17.0 (432)
Weight - lb (kg)	3250 (1474)
Compression Ratio	17.3:1
Displacement - cu. in. (l)	763 (12.5)
Engine Type	4 Stroke Cycle - Inline Construction

Abbreviations: TRWA - Turbocharged and Raw Water Aftercooled CW - Clockwise
*Rotation viewed from Heat Exchanger / Front of engine

CERTIFIED POWER RATING

- Each engine is factory tested to verify power and performance
- FM-UL power ratings are shown at specific speeds. Clarke engines can be applied at a single rated RPM setting +/- 50 RPM.

ENGINE RATINGS BASELINES

- Engines are to be used for stationary emergency standby fire pump service only. Engines are to be tested in accordance with NFPA 25.
- Engines are rated at standard SAE conditions of 29.61 in. (752.1 mm) 77°F (25°C) inlet air temperature [approximates 300 ft. (91.4 m) above sea level] by the testing laboratory (see SAE Standard J 1349).
- A deduction of 3 percent from engine horsepower rating at standard SAE conditions shall be made for diesel engines for each 1000 ft. (305 m) altitude above 300 ft. (91.4 m)
- A deduction of 1 percent from engine horsepower rating as corrected to standard SAE conditions shall be made for diesel engines for every 10°F (5.6°C) above 77°F (25°C) ambient temperature.

c UL us LISTED NFPA c FM us APPROVED

ENGINE EQUIPMENT

EQUIPMENT	STANDARD	OPTIONAL
Air Cleaner with Air Differential Gauge	Direct Mounted, Washable, Indoor Service with Drip Shield	Disposable, Drip Proof, Indoor Service Outdoor Type, Single or Two Stage
Alarm	Overspeed Alarm & Shutdown, Low Oil Pressure, Low & High Coolant Temperature, Low Raw Water Flow, High Raw Water Temperature, Alternate ECM Warning, Fuel Injection Malfunction, ECM Warning and Failure with Automatic Switching	Low Coolant Level, Low Oil Level, Oil Filter Differenetial Pressure, Fuel Filter Differential Pressure, Air Filter Restriction
Alternator	24V-DC, 50 Amps with V-Belt and Guard	
Coupling	Bare Flywheel	Driveshaft and Guard
Crankcase Ventilation		Crankcase Breather
Engine Heater	230V-AC, 2000 Watt	
Exhaust Flex Connection	SS Flex. 150# ANSI Flanged Connection. 6”	SS Flex. 150# ANSI Flanged Connection. 8”
Exhaust Protection	Metal Guard on Manifold and Turbochargers	
Flywheel Housing	SAE #1	
Flywheel Power Take Off	14” SAE Industrial Flywheel Connection	
Fuel Connections	Fire Resistent Supply and Return Lines	SS, Braided, cUL Listed, Supply and Return Lines
Fuel Filter	Primary Filter / Water Separator, Secondary Filter with Priming Pump	Duplex Secondary Filter
Fuel Injection System	Unit Injector	
Governor, Speed	Electronic, Dual Electronic Engine Control Modules	
Heat Exchanger	Serviceable Shell and Tube Type, 60 PSI (4 Bar), NPT (F) Connections	Serviceable 90/10 CuNi Sea Water Compatible
Instrument Panel	NEMA Type 2, Powder Coated Steel Construction, Multimeter to Display English and Metric, Tachometer, Hour meter, Water Temperature, Oil Pressure, and Dual Voltmeters, Front Opening, Soft Start for Commissioning	316 Stainless Steel NEMA 4X/IP66
Junction Box	Integral with Instrument Panel; For DC Wiring Interconnection to Engine Controller	
Lube Oil Cooler	Jacket Water Cooled, Shell and Tube Type	
Lube Oil Filter	Full Flow, Dual Element, Qty 2	Duplex Filter
Lube Oil Pump	Gear Driven, Gear Type	
Manual Start Control	Dual Manual Start Contactors & On Instrument Panel with Control Position Warning Light	
Overspeed Control	Electronic, Factory Set	
Raw Water Cooling Loop w/ Alarms	Galvanized	90/10 CuNi Seawater, All 316 SS, High Pressure
Raw Water Solenoid Operation	Automatic from Fire Pump Controller and from Engine Instrument Panel (for Horizontal Fire Pump Applications)	
Run - Stop Control	On Instrument Panel with Control Position Warning Light	
Starters	One (1) 24V-DC	
Throttle Control	Adjustable Speed Control by Increase/Decrease Button, Tamper Proof Adjustable Speed Control	
Water Pump	Centrifugal Type, Gear Driven	

Abbreviations: DC - Direct Current, AC - Alternating Current, SAE - Society of Automotive Engineers, BSP(F) - British Standard Pipe Thread (Female), SS - Stainless Steel

MODEL NOMENCLATURE (11 Digit Models)

C13H0-UFAD78

Base Engine
12.5 Liter
Heat Exchanger Cooled
Non-Hazardous Environment
Rating Code
EPA Tier 3 Certified (“C” = EPA Tier 2 Certified, “A” = Non-Emissionized)
Built in USA
UL Listed and FM Approved

Specifications and information contained in this brochure is subject to change without notice.

CLARKE®

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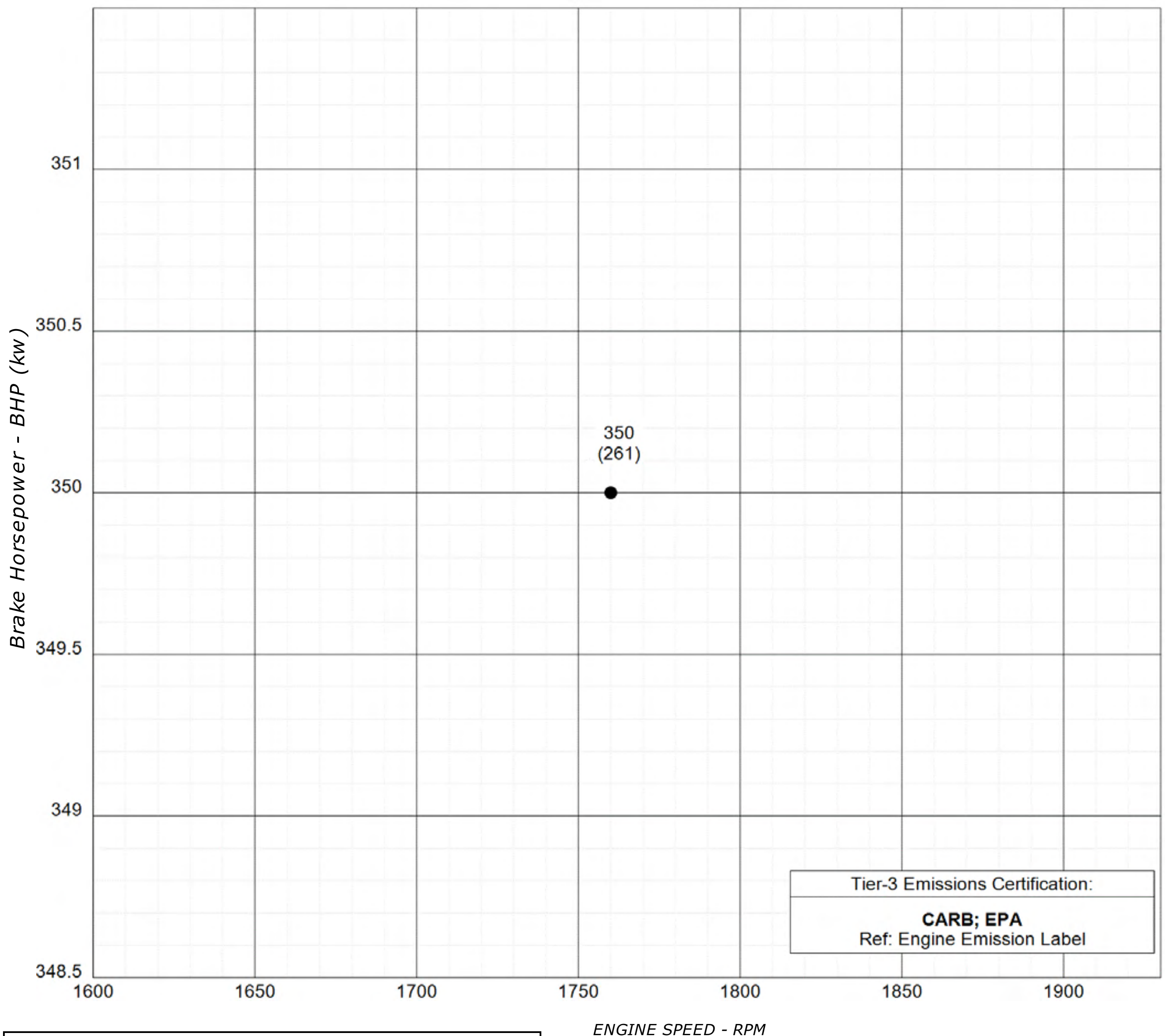
FIRE PUMP MODEL: C13H0-UFAD38
Heat Exchanger Cooled/Turbocharged
Raw Water Charge Cooling
13 Liter, 6 Cylinder



RESTRICTED:
Use only for Stand-By Fire Pump Applications

●———● *NAMEPLATE BHP (MAXIMUM PUMP LOAD)*

ENGINE PERFORMANCE:
STANDARD CONDITIONS: (SAE J1349, ISO 3046)
77°F (25°C) AIR INLET TEMPERATURE
29.61 IN. (752.1MM) HG BAROMETRIC PRESSURE
#2 DIESEL FUEL (SEE C13940)

Cory L. Robbins
Cory Robbins 29JUL22

CREATED	DATE CREATED
CLR	07/29/22

ENGINE MODEL C13H0-UFAD38

DRAWING NO.	REV
C138497	A

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C13H0-UFAD38
INSTALLATION & OPERATION DATA (I&O)

Basic Engine Description

Engine Manufacturer	Caterpillar
Ignition Type	Compression (Diesel)
Number of Cylinders	6
Bore and Stroke - in (mm)	5.1 (130) X 6.2 (157)
Displacement - in³ (L)	763 (12.5)
Compression Ratio	17.3:1
Valves per cylinder	
Intake	2
Exhaust	2
Combustion System	Direct Injection
Engine Type	In-Line, 4 Stroke Cycle
Fuel Management Control	Electronic, Unit Injector
Firing Order (CW Rotation)	1-5-3-6-2-4
Aspiration	Turbocharged
Charge Air Cooling Type	Raw Water Cooled
Rotation, viewed from front of engine, Clockwise (CW)	Standard
Engine Crankcase Vent System	Open
Installation Drawing	D891
Weight - lb (kg)	3250 (1470)

Power Rating	**1760**
Nameplate Power - HP (kW) [1]	350 (261)

Cooling System	**1760**
Engine Coolant Heat - Btu/sec (kW)	156 (165)
Engine Radiated Heat - Btu/sec (kW)	25 (26.4)
Heat Exchanger Minimum Flow - [C053702]	
60°F (15°C) Raw H_2O - gal/min (L/min)	18 (68.1)
100°F (37°C) Raw H_2O - gal/min (L/min)	29 (110)
Heat Exchanger Maximum Cooling Raw Water - [C053702]	
Inlet Pressure - psi (bar)	60 (4.1)
Flow - gal/min (L/min)	100 (379)
Optional Sea Water Heat Exchanger (90/10 CuNi) Minimum Flow - []	
60°F (15°C) Raw H_2O - gal/min (L/min)	
100°F (37°C) Raw H_2O - gal/min (L/min)	
Optional Sea Water Heat Exchanger (90/10 CuNi) Maximum Cooling Raw Water - []	
Inlet Pressure - psi (bar)	
Flow - gal/min (L/min)	
Typical Engine H_2O Operating Temp - °F (°C)	190 (87.8) - 200 (93.3)
Thermostat	
Start to Open - °F (°C)	189 (87.2)
Fully Opened - °F (°C)	208 (97.8)
Engine Coolant Capacity - qt (L)	35 (33.1)
Coolant Pressure Cap - lb/in² (kPa)	10 (68.9)
Maximum Engine Coolant Temperature - °F (°C)	219 (104)
Minimum Engine Coolant Temperature - °F (°C)	160 (71.1)
High Coolant Temp Alarm Switch - °F (°C)	210 (98.9)

Electric System - DC	**Standard**	
System Voltage (Nominal)	24	
Battery Capacity for Ambients Above 32°F (0°C)		
Voltage (Nominal)12	12	{C07633}
Qty. Per Battery Bank	2	
SAE size per J537	8D	
CCA @ 0°F (-18°C) per J537	1200	
Reserve Capacity - Minutes per J537	430	
Battery Cable Circuit, Max Resistance - ohm	0.0013	
Battery Cable Minimum Size		
0-120 in. Circuit Length [2]	00	
121-160 in. Circuit Length [2]	000	
161-200 in. Circuit Length [2]	0000	
Charging Alternator Maximum Output - Amp,	50	{C073361}
Starter Cranking Amps, Rolling - @60°F (15°C)	375	{C073380}

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C13H0-UFAD38
INSTALLATION & OPERATION DATA (I&O)

Exhaust System (Single Exhaust Outlet)	1760
Exhaust Flow - ft.³/min (m³/min)	2360 (66.8)
Exhaust Temperature - °F (°C) (corrected to 77°F)	812 (433)
Maximum Allowable Back Pressure - in H_2O (kPa)	30 (7.5)
Minimum Exhaust Pipe Dia. - in (mm) [3]	6 (152)

Fuel System	1760
Fuel Consumption - gal/hr (L/hr)	18.1 (68.5)
Fuel Return - gal/hr (L/hr)	59.9 (227)
Fuel Supply - gal/hr (L/hr)	78.0 (295)
Fuel Pressure - lb/in² (kPa)	85 (586) - 95 (655)
Minimum Line Size - Supply - in.	.75 Schedule 40 Steel Pipe
Pipe Outer Diameter - in (mm)	1.05 (26.7)
Minimum Line Size - Return - in.	.50 Schedule 40 Steel Pipe
Pipe Outer Diameter - in (mm)	0.848 (21.5)
Max. Allowable Fuel Pump Suction Lift w/ clean Filter at Customer Connection Block - in H_2O (mH_2O)	71 (1.8)
Maximum Allowable Fuel Head above Fuel pump, Supply or Return - ft (m)	15 (4.6)
Fuel Filter Micron Size	2 (Secondary)
Maximum fuel supply temperature - °F (°C)	

Heater System	Standard	Optional
Engine Coolant Heater		
Wattage (Nominal)	2000	2000
Voltage - AC, 1 Phase	115 (+5%, -10%)	230 (+5%, -10%)
Part Number	{C122189}	{C122193}

Air System	1760	
Combustion Air Flow - ft.³/min (m³/min)	745 (21.1)	
Air Cleaner	**Standard**	**Optional**
Part Number	{C03244}	{C03330}
Type	Indoor Service Only, with Shield	Canister, Single-Stage
Cleaning method	Washable	Disposable
Air Intake Restriction Maximum Limit		
Dirty Air Cleaner - in H_2O (kPa)	22 (5.5)	22 (5.5)
Clean Air Cleaner - in H_2O (kPa)	15 (3.7)	15 (3.7)
Maximum Allowable Temperature (Air To Engine Inlet) - °F (°C)	120 (48.9)	

Lubrication System	
Oil Pressure - normal - lb/in² (kPa)	30 (207) - 55 (379)
Low Oil Pressure Alarm Switch - lb/in² (kPa)	
In Pan Oil Temperature - °F (°C)	200 (93.3) - 230 (110)
Total Oil Capacity with Filter - qt (L)	36 (34.1)

Lube Oil Heater	Optional	Optional
Wattage (Nominal)	300	300
Voltage	120V (+5%, -10%)	240V (+5%, -10%)
Part Number	{C04559}	{C04560}

Performance	1760
BMEP - lb/in² (kPa)	206 (1420)
Piston Speed - ft/min (m/min)	1819 (554)
Mechanical Noise - dB(A) @ 1m	
Power Curve	C138497 - Reference Power Curve on Engine Page at www.clarkefire.com

NOTE: This engine is intended for indoor installation or in a weatherproof enclosure. [1] Derate 3% per every 1000 ft. 304.8m above 300 ft. 91.4m and derate 1% for every 10°F 5.55 °C above 77°F 25°C. [2] Positive and Negative Cables Combined Length. [3] Minimum Exhaust Pipe Diameter is based on: 15 feet of pipe, one 90° elbow, and one Industrial silencer. A Back-pressure flow analysis must be performed on the actual field installed exhaust system to assure engine maximum allowable back pressure is not exceeded. See Exhaust Sizing Calculator on www.clarkefire.com. { } indicates component reference part number.

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C13H0 ENGINE MODELS
ENGINE MATERIALS AND CONSTRUCTION

Air Cleaner
Type……………..……………. .. .. Indoor Usage Only
Oiled Fabric Pleats
Material……….…..………………. Surgical Cotton, Aluminum Mesh

Air Cleaner - Optional
Type………………………………. Canister
Material…………………………… Pleated Paper
Housing………………….……….. Enclosed

Camshaft
Material………….……………..… Forged Steel, Hardened
Location……………..…………… In Head
Drive……………….………….…. Gear, Spur
Type of Cam………………..…… Ground

Charge Air Cooler
Type……………………………… Raw Water Cooled

Materials (in contact with raw water)
Tubes…………………………… 90/10 CU/NI
Headers ……………………… 36500 Muntz
Covers…… …………………… 83600 Red Brass
Plumbing…. …………………… 316 Stainless Steel/ Brass
90/10 Silicone

Coolant Pump
Type……… ……………………. Centrifugal
Drive……… ……………………. Gear

Coolant Thermostat
Type………………………………. Full Blocking
Qty…………………………………. 1

Cooling Loop (Galvanized)
Tees, Elbows, Pipe……………. Galvanized Steel
Ball Valves……………………… Brass ASTM B 124
Solenoid Valve…………………. Brass
Pressure Regulator……………. Bronze
Strainer…………………………… Cast Iron (1/2"- 1" Loops)
or Bronze (1.25" - 2" Loops)

Cooling Loop (Sea Water)
Tees, Elbows, Pipe……………. 316 Stainless Steel
Ball Valves……………………… 316 Stainless Steel
Solenoid Valve…………………. 316 Stainless Steel
Pressure Regulator/Strainer….. Cast Brass ASTM B176 C87800

Cooling Loop (316SS)
Tees, Elbows, Pipe……………. 316 Stainless Steel
Ball Valves……………………… 316 Stainless Steel
Solenoid Valve…………………. 316 Stainless Steel
Pressure Regulator/Strainer….. 316 Stainless Steel

Cooling Loop (90/10 CuNi)
Tees, Elbows, Pipe……………. 90/10 CuNi
Ball Valves……………………… 922 Bronze Body/316SS Ball
Solenoid Valve…………………. 316 Stainless Steel
Pressure Regulator/Strainer….. Cast Brass C87800

Connecting Rod
Type………………………………. I-Beam Taper
Material…………………………… Forged Steel Alloy

Crank Pin Bearings
Type………………………………. Precision Half Shell
Number…………………………… 1 Pair Per Cylinder

Crankshaft
Material…………………………… Forged Steel
Type of Balance………………… Dynamic

Cylinder Block
Type………………………………. One Piece
Material…………………………… Grey Iron

Cylinder Head
Type…….. ……………………. Slab 4 Valve
Material……………………… Cast Iron

Cylinder Liners
Type…….. ……………………. Centrifugal Cast, Wet Liner
Material…………………….……. Compacted Graphite and Iron

Valves
Type…….. ……………………. Poppet
Material……………………….…. Steel Alloy
Arrangement…………………… Overhead Valve
Number/Cylinder……………… 2 intake/2 exhaust
Operating Mechanism………… Mechanical Rocker Arm
Type of Lifter…………………… Solid Roller
Valve Seat Insert………………. Replaceable

Exhaust Manifold
Material…. ……………………. Iron Alloy

Fuel Pump
Type……… ……………………. Gear
Drive……………………………… Gear

Heat Exchanger (Serviceable)
Type………………………………. Shell & Tube
Materials
Tube………………………………. Copper C122
Header Assy…………………. Copper C122/Nylon/EPDM Rubber
Shell……… ……………………. Aluminum 356-T6
Endcaps…. ……………………. Cast Iron CL 30/Aluminum 356-T6
Electrode…………………………. Zinc

Sea Water Heat Exchanger (90/10 CuNi)
Type………………………………. Shell & Tube
Materials
Tube………………………………. CuNi 70600
Header Assy…………………. CuNi 70600/Nylon/Rubber
Shell……… ……………………. Aluminum 356-T6
Endcaps…. ……………………. C836 Bronze
Electrode…………………………. Zinc

Injection Pump
Type………………………………. Electronic Unit Injector
Drive………………………………. Cam Shaft

Lubrication Cooler
Type………………………………. Shell & Tube

Lubrication Pump
Type………………………………. Gear Pump
Drive……………………………… Gear

Main Bearings
Type………………………………. Precision Half Shells

Piston

Type and Material……………… Aluminum Alloy
Cooling…………………………… Oil Jet Spray

Piston Pin
Type………………………………. Full Floating

Piston Rings
Number/Piston…………………. 3

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C18H0 MODELS

UFAD12	UFAD20	UFAD58	UFAC18
UFAD18	UFAD38	UFAD50	UFAC10
UFAD22	UFAD42	UFAD68	UFAC28
UFAD10	UFAD30	UFAA78	UFAC20
UFAD32	UFAD48	UFAD78	
UFAD28	UFAD40	UFAD70	

UL/FM - cUL APPROVED RATINGS BHP/kW

C18H0 MODEL ♦	RATED SPEED 1470		1760		1900		2100		EMISSIONS
UFAD12*	**450**	*335*							EPA Tier 3 Certified
UFAD18			**460**	*343*					EPA Tier 3 Certified
UFAD22*	**475**	*354*							EPA Tier 3 Certified
UFAD10					**488**	*364*	**488**	*364*	EPA Tier 3 Certified
UFAD32*	**491**	*366*							EPA Tier 3 Certified
UFAD28			**510**	*380*					EPA Tier 3 Certified
UFAD20					**525**	*392*	**525**	*392*	EPA Tier 3 Certified
UFAD38			**542**	*404*					EPA Tier 3 Certified
UFAD42	**570**	*425*							EPA Tier 3 Certified
UFAD30					**575**	*429*	**575**	*429*	EPA Tier 3 Certified
UFAD48			**600**	*447*					EPA Tier 3 Certified
UFAD40					**600**	*447*	**600**	*447*	EPA Tier 3 Certified
UFAD58			**650**	*485*					EPA Tier 3 Certified
UFAD50					**650**	*485*	**650**	*485*	EPA Tier 3 Certified
UFAD68			**687**	*512*					EPA Tier 3 Certified
UFAA78	**700**	*522*							Non-Emissionized
UFAD78			**700**	*522*					EPA Tier 3 Certified
UFAD70					**700**	*522*	**700**	*522*	EPA Tier 3 Certified
UFAC18			**755**	*563*					EPA Tier 2 Certified
UFAC10					**755**	*563*	**755**	*563*	EPA Tier 2 Certified
UFAC28			**800**	*596.5*					EPA Tier 2 Certified
UFAC20					**800**	*596.5*	**800**	*596.5*	EPA Tier 2 Certified

*Utilizes a single turbo base engine.

♦ All Models are available for export

ENGINE SPECIFICATIONS	
Number of Cylinders	6
Aspiration	TRWA
Rotation*	CW
Overall Dimensions - in. (mm)	66.1(1678) H X 79.6(2022) L X 45.2(1147) W
Crankshaft Centerline Height - in. (mm)	17.0 (432)
Weight - lb (kg)	4100 (1860)
Compression Ratio	16.3:1
Displacement - cu. in. (l)	1104 (18.1)
Engine Type	4 Stroke Cycle - Inline Construction

Abbreviations: TRWA - Turbocharged and Raw Water Aftercooled   CW - Clockwise
*Rotation viewed from Heat Exchanger / Front of engine

CERTIFIED POWER RATING

- Each engine is factory tested to verify power and performance
- FM-UL power ratings are shown at specific speeds. Clarke engines can be applied at a single rated RPM setting +/- 50 RPM.

ENGINE RATINGS BASELINES

- Engines are to be used for stationary emergency standby fire pump service only. Engines are to be tested in accordance with NFPA 25.
- Engines are rated at standard SAE conditions of 29.61 in. (752.1 mm) 77°F (25°C) inlet air temperature [approximates 300 ft. (91.4 m) above sea level] by the testing laboratory (see SAE Standard J 1349).
- A deduction of 3 percent from engine horsepower rating at standard SAE conditions shall be made for diesel engines for each 1000 ft. (305 m) altitude above 300 ft. (91.4 m)
- A deduction of 1 percent from engine horsepower rating as corrected to standard SAE conditions shall be made for diesel engines for every 10°F (5.6°C) above 77°F (25°C) ambient temperature.

ENGINE EQUIPMENT

EQUIPMENT	STANDARD	OPTIONAL
Air Cleaner with Air Differential Gauge	Direct Mounted, Washable, Indoor Service with Drip Shield	Disposable, Drip Proof, Indoor Service Outdoor Type, Single or Two Stage
Alarm	Overspeed Alarm & Shutdown, Low Oil Pressure, Low & High Coolant Temperature, Low Raw Water Flow, High Raw Water Temperature, Alternate ECM Warning, Fuel Injection Malfunction, ECM Warning and Failure with Automatic Switching	Low Coolant Level, Low Oil Level, Oil Filter Differenetial Pressure, Fuel Filter Differential Pressure, Air Filter Restriction
Alternator	24V-DC, 50 Amps with V-Belt and Guard	
Coupling	Bare Flywheel	Driveshaft and Guard
Crankcase Ventilation		Crankcase Breather
Engine Heater	230V-AC, 3500 Watt	
Exhaust Flex Connection	SS Flex. 150# ANSI Flanged Connection. 8”	SS Flex. 150# ANSI Flanged Connection. 10”
Exhaust Protection	Metal Guard on Manifold and Turbocharges	
Flywheel Housing	SAE #1	
Flywheel Power Take Off	14” SAE Industrial Flywheel Connection	
Fuel Connections	Fire Resistent Supply and Return Lines	SS, Braided, cUL Listed, Supply and Return Lines
Fuel Filter	Primary Filter / Water Separator with Priming Pump, Secondary Filter	
Fuel Injection System	Unit Injector	
Governor, Speed	Electronic, Dual Electronic Engine Control Modules	
Heat Exchanger	Shell and Tube Type, 60 PSI (4 Bar), NPT (F) Connections - Sea Water Compatible	
Instrument Panel	NEMA Type 2, Powder Coated Steel Construction, Multimeter to Display English and Metric, Tachometer, Hour meter, Water Temperature, Oil Pressure, and Dual Voltmeters, Front Opening, Soft Start for Commissioning	316 Stainless Steel NEMA 4X/IP66
Junction Box	Integral with Instrument Panel; For DC Wiring Interconnection to Engine Controller	
Lube Oil Cooler	Jacket Water Cooled, Shell and Tube Type	
Lube Oil Filter	Full Flow, Dual Element	
Lube Oil Pump	Gear Driven, Gear Type	
Manual Start Control	Dual Manual Start Contactors & On Instrument Panel with Control Position Warning Light	
Overspeed Control	Electronic, Factory Set	
Raw Water Cooling Loop w/ Alarms	Galvanized	Seawater, All 316 SS, High Pressure
Raw Water Solenoid Operation	Automatic from Fire Pump Controller and from Engine Instrument Panel (for Horizontal Fire Pump Applications)	
Run - Stop Control	On Instrument Panel with Control Position Warning Light	
Starters	One (1) 24V-DC	
Throttle Control	Adjustable Speed Control by Increase/Decrease Button, Tamper Proof Adjustable Speed Control	
Water Pump	Centrifugal Type, Gear Driven	

Abbreviations: DC - Direct Current, AC - Alternating Current, SAE - Society of Automotive Engineers, BSP(F) - British Standard Pipe Thread (Female), SS - Stainless Steel

MODEL NOMENCLATURE (11 Digit Models)

C18H0-UFAD78

Base Engine
18 Liter
Heat Exchanger Cooled
Non-Hazardous Environment

Rating Code
EPA Tier 3 Certified (“C” = EPA Tier 2 Certified, “A” = Non-Emissionized)
Built in USA
UL Listed and FM Approved

Specifications and information contained in this brochure is subject to change without notice.

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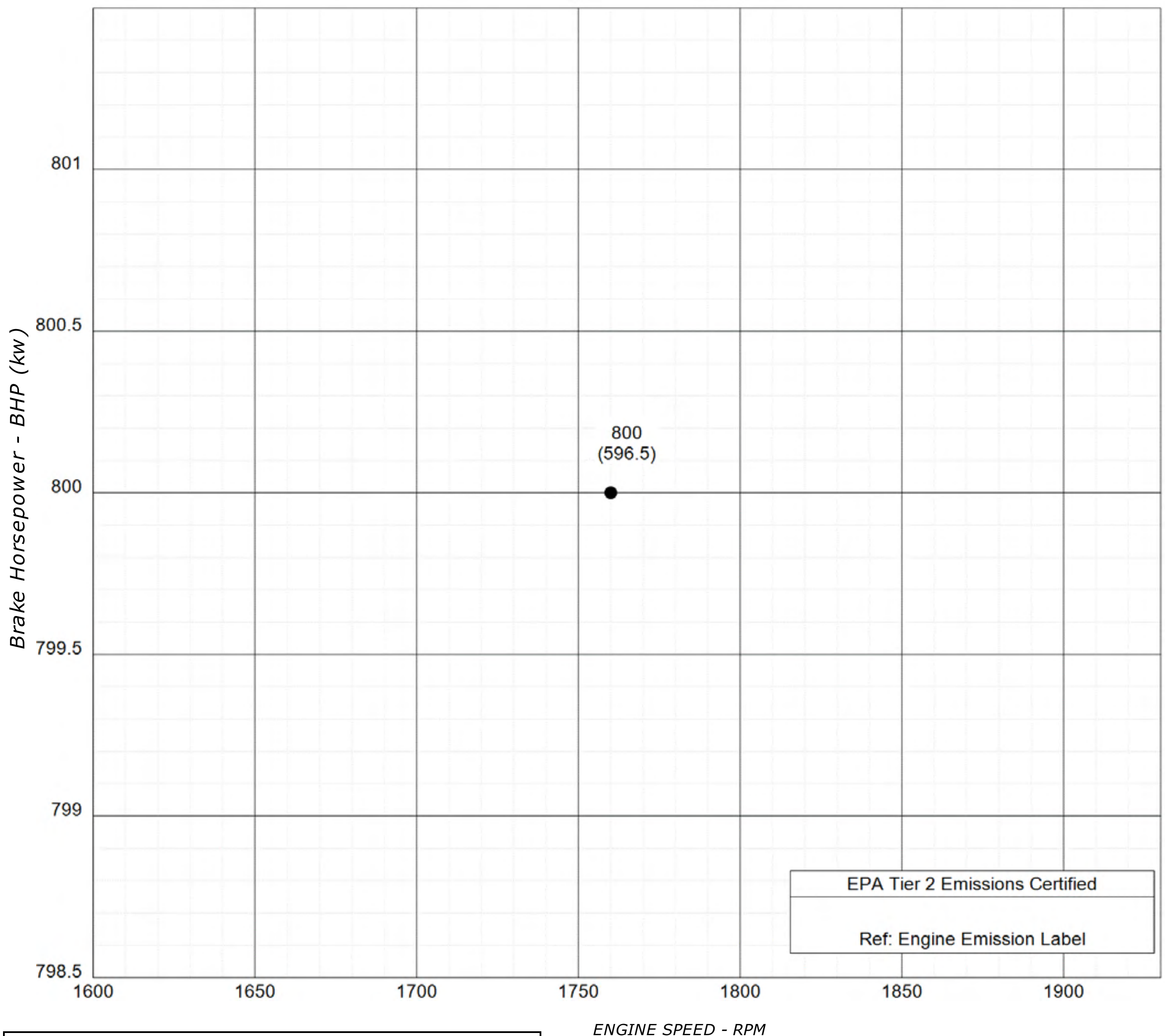
FIRE PUMP MODEL: C18H0-UFAC28
Heat Exchanger Cooled/Turbocharged
Raw Water Charge Cooling
18 Liter, 6 Cylinder



RESTRICTED:
Use only for Stand-By Fire Pump Applications

NAMEPLATE BHP (MAXIMUM PUMP LOAD)

ENGINE PERFORMANCE:
STANDARD CONDITIONS: (SAE J1349, ISO 3046)
77°F (25°C) AIR INLET TEMPERATURE
29.61 IN. (752.1MM) HG BAROMETRIC PRESSURE
#2 DIESEL FUEL (SEE C13940)

Cory L. Robbins
Cory Robbins 15APR19

CREATED	DATE CREATED
CLR	04/15/19

ENGINE MODEL C18H0-UFAC28

DRAWING NO.	REV
C137810	A

CLARKE®

C18H0-UFAC28
INSTALLATION & OPERATION DATA (I&O)

Basic Engine Description

Engine Manufacturer	Caterpillar
Ignition Type	Compression (Diesel)
Number of Cylinders	6
Bore and Stroke - in (mm)	5.71 (145) X 7.2 (183)
Displacement - in³ (L)	1106 (18.1)
Compression Ratio	16.3:1
Valves per cylinder	
Intake	2
Exhaust	2
Combustion System	Compression (Diesel)
Engine Type	In-Line, 4 Stroke Cycle
Fuel Management Control	Electronic, Unit Injector
Firing Order (CW Rotation)	1-5-3-6-2-4
Aspiration	Twin Turbocharged
Charge Air Cooling Type	Raw Water Cooled
Rotation, viewed from front of engine, Clockwise (CW)	Standard
Engine Crankcase Vent System	Open
Installation Drawing	D844
Weight - lb (kg)	4100 (1860)

Power Rating	**1760**
Nameplate Power - HP (kW) [1]	800 (596.5)

Cooling System	**1760**
Engine Coolant Heat - Btu/sec (kW)	293 (309)
Engine Radiated Heat - Btu/sec (kW)	62 (65.4)
Heat Exchanger Minimum Flow - [C051389]	
60°F (15°C) Raw H_2O - gal/min (L/min)	27 (102)
100°F (37°C) Raw H_2O - gal/min (L/min)	35 (132)
Heat Exchanger Maximum Cooling Raw Water - [C051389]	
Inlet Pressure - psi (bar)	60 (4.1)
Flow - gal/min (L/min)	190 (719)
Typical Engine H_2O Operating Temp - °F (°C)	185 (85) - 200 (93.3)
Thermostat	
Start to Open - °F (°C)	189 (87.2)
Fully Opened - °F (°C)	208 (97.8)
Engine Coolant Capacity - qt (L)	40 (37.9)
Coolant Pressure Cap - lb/in² (kPa)	10 (68.9)
Maximum Engine Coolant Temperature - °F (°C)	219 (104)
Minimum Engine Coolant Temperature - °F (°C)	160 (71.1)
High Coolant Temp Alarm Switch - °F (°C)	217 (103)

Electric System - DC	**Standard**	
System Voltage (Nominal)	24	
Battery Capacity for Ambients Above 32°F (0°C)		
Voltage (Nominal)12	12	{C07633}
Qty. Per Battery Bank	2	
SAE size per J537	8D	
CCA @ 0°F (-18°C) per J537	1200	
Reserve Capacity - Minutes per J537	430	
Battery Cable Circuit, Max Resistance - ohm	0.0012	
Battery Cable Minimum Size		
0-120 in. Circuit Length [2]	00	
121-160 in. Circuit Length [2]	000	
161-200 in. Circuit Length [2]	0000	
Charging Alternator Maximum Output - Amp,	50	{1693345}
Starter Cranking Amps, Rolling - @60°F (15°C)	375	{C072743}

Exhaust System (Single Exhaust Outlet)	**1760**	
Exhaust Flow - ft.³/min (m³/min)	4283 (121)	
Exhaust Temperature - °F (°C) (corrected to 77°F)	1040 (560)	
Maximum Allowable Back Pressure - in H_2O (kPa)	40 (10)	
Minimum Exhaust Pipe Dia. - in (mm) [3]	8 (203)	
Fuel System	**1760**	
Fuel Consumption - gal/hr (L/hr)	40 (151)	
Fuel Return - gal/hr (L/hr)	67 (254)	
Fuel Supply - gal/hr (L/hr)	107.0 (405)	
Fuel Pressure - lb/in² (kPa)	90 (621) - 110 (758)	
Minimum Line Size - Supply - in.	.75 Schedule 40 Steel Pipe	
Pipe Outer Diameter - in (mm)	1.05 (26.7)	
Minimum Line Size - Return - in.	.50 Schedule 40 Steel Pipe	
Pipe Outer Diameter - in (mm)	0.848 (21.5)	
Max. Allowable Fuel Pump Suction Lift w/ clean Filter at Customer Connection Block - in H_2O (mH_2O)	71 (1.8)	
Maximum Allowable Fuel Head above Fuel pump, Supply or Return - ft (m)	15 (4.6)	
Fuel Filter Micron Size	2 (Secondary)	
Maximum fuel supply temperature - °F (°C)		
Heater System	**Standard**	**Optional**
Engine Coolant Heater		
Wattage (Nominal)	3500	
Voltage - AC, 1 Phase	230	
Part Number	{C127975}	
Air System	**1760**	
Combustion Air Flow - ft.³/min (m³/min)	1501 (42.5)	
Air Cleaner	**Standard**	**Optional**
Part Number	{C03244 Qty (2)}	{C03327 Qty (2)}
Type	Indoor Service Only, with Shield	Canister Single-Stage
Cleaning method	Washable	Disposable
Air Intake Restriction Maximum Limit		
Dirty Air Cleaner - in H_2O (kPa)	30 (7.5)	30 (7.5)
Clean Air Cleaner - in H_2O (kPa)	15 (3.7)	15 (3.7)
Maximum Allowable Temperature (Air To Engine Inlet) - °F (°C)	120 (48.9)	
Lubrication System		
Oil Pressure - normal - lb/in² (kPa)	40 (276) - 70 (483)	
Low Oil Pressure Alarm Switch - lb/in² (kPa)	22 (152)	
In Pan Oil Temperature - °F (°C)	203 (95) - 233 (112)	
Total Oil Capacity with Filter - qt (L)	48 (45.4)	
Lube Oil Heater	**Optional**	**Optional**
Wattage (Nominal)	300	300
Voltage	120V (+5%, -10%)	240V (+5%, -10%)
Part Number	{C04559}	{C04560}
Performance	**1760**	
BMEP - lb/in² (kPa)	325 (2240)	
Piston Speed - ft/min (m/min)	2112 (644)	
Mechanical Noise - dB(A) @ 1m	C137854 - Reference Noise data on Engine Page at www.clarkefire.com	
Power Curve	C137810 - Reference Power Curve on Engine Page at www.clarkefire.com	

NOTE: This engine is intended for indoor installation or in a weatherproof enclosure. [1] Derate 3% per every 1000 ft. 304.8m above 300 ft. 91.4m and derate 1% for every 10°F 5.55 °C above 77°F 25°C. [2] Positive and Negative Cables Combined Length. [3] Minimum Exhaust Pipe Diameter is based on: 15 feet of pipe, one 90° elbow, and one Industrial silencer. A Back-pressure flow analysis must be performed on the actual field installed exhaust system to assure engine maximum allowable back pressure is not exceeded. See Exhaust Sizing Calculator on www.clarkefire.com. { } indicates component reference part number.

CLARKE®

C18H0 ENGINE MODELS
ENGINE MATERIALS AND CONSTRUCTION

Air Cleaner
Type………….…………. .. .. Indoor Usage Only
Oiled Fabric Pleats
Material……..….…………… Surgical Cotton, Aluminum Mesh

Air Cleaner - Optional
Type……………………………… Canister
Material………………………….. Pleated Paper
Housing……………….……….. Enclosed

Camshaft
Material………….…………..… Forged Steel, Hardened
Location…………..…….….…. In Head
Drive……………….…………… Gear, Spur
Type of Cam…………………… Ground

Charge Air Cooler
Type…………………………….. Raw Water Cooled

Materials (in contact with raw water)
Tubes…….. …………………….. 90/10 CU/NI
Headers …………………….. 36500 Muntz
Covers…… …………………….. 83600 Red Brass
Plumbing…. …………………….. 316 Stainless Steel/ Brass
90/10 Silicone

Coolant Pump
Type…………………………….. Centrifugal
Drive……… …………. ………….. Gear

Coolant Thermostat
Type……………………………… Full Blocking
Qty………………………………. 2

Cooling Loop (Galvanized)
Tees, Elbows, Pipe…………….. Galvanized Steel
Ball Valves………………………. Brass ASTM B 124
Solenoid Valve………………….. Brass
Pressure Regulator…………….. Bronze
Strainer………………………….. Cast Iron (1/2"- 1" Loops)
or Bronze (1.25" - 2" Loops)

Cooling Loop (Sea Water)
Tees, Elbows, Pipe…………….. 316 Stainless Steel
Ball Valves………………………. 316 Stainless Steel
Solenoid Valve………………….. 316 Stainless Steel
Pressure Regulator/Strainer…… Cast Brass ASTM B176 C87800

Cooling Loop (316SS)
Tees, Elbows, Pipe…………….. 316 Stainless Steel
Ball Valves………………………. 316 Stainless Steel
Solenoid Valve………………….. 316 Stainless Steel
Pressure Regulator/Strainer…… 316 Stainless Steel

Connecting Rod
Type……………………………… I-Beam Taper
Material………………………….. Forged Steel Alloy

Crank Pin Bearings
Type……………………………… Precision Half Shell
Number………………………….. 1 Pair Per Cylinder
Material………………………….. Steel-backed Copper
with Lead Tin Overlay

Crankshaft
Material………………………….Forged Steel
Type of Balance………………… Dynamic

Cylinder Block
Type……………………………..One Piece
Material………………………….Grey Iron

Cylinder Head
Type…….. ……………………. Slab 4 Valve
Material……………………. Cast Iron

Cylinder Liners
Type…….. ……………………. Centrifugal Cast, Wet Liner
Material……………….………. Compacted Graphite and Iron

Valves
Type…….. ……………………. Poppet
Material……………….………. Steel Alloy
Arrangement…………………… Overhead Valve
Number/Cylinder………………..2 intake/2 exhaust
Operating Mechanism…………. Mechanical Rocker Arm
Type of Lifter…………………… Solid Roller
Valve Seat Insert………………. Replaceable

Exhaust Manifold
Material…… ……………………. Iron Alloy

Fuel Pump
Type……… ……………………. Gear
Drive……………………………. Cam Lobe

Heat Exchanger
Type……………………………..Shell & Tube
Materials
Tube& Headers………………… Copper
Shell……… ……………………. Copper
Electrode………………………..Zinc

Injection Pump
Type……………………………..Electronic Unit Injector
Drive…………………………….. Cam Shaft

Lubrication Cooler
Type……………………………..Shell & Tube

Lubrication Pump
Type……………………………..Gear Pump
Drive……………………………. Gear

Main Bearings
Type……………………………..Precision Half Shells
Material………………………….Steel Backed-Aluminum Lined

Piston
Type and Material………………Single-piece Steel

Cooling………………………….. Oil Jet Spray

Piston Pin
Type……………………………..Full Floating

Piston Rings
Number/Piston………………… 3

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